INL/JOU-17-42292
Accepted Manuscript

Early Nuclear Retirements in Deregulated U.S. Markets: Causes, Implications and Policy Options

G. Haratyk
(Massachusetts Institute of Technology)

June 2017

Prepared for the U.S. Department of Energy
Office of Nuclear Energy
Under DOE Idaho Operations Office
Contract DE-AC07-05ID14517

Idaho National Laboratory

Early Nuclear Retirements in Deregulated U.S. Markets: Causes, Implications and Policy Options

Geoffrey Haratyk[*a]

[a]Massachusetts Institute of Technology, 77 Massachusetts Avenue, Cambridge, MA 02139, Unites States

Abstract

Electricity prices have fallen significantly since 2008, putting commercial nuclear reactors in the United States under substantial financial pressure. In this market environment driven by persistently low natural gas prices and stagnant electricity demand, we estimate that about two thirds of the 100 GW nuclear capacity are uncompetitive over the next few years under the current trajectory. Among those, 18 GW are retiring or are merchant plants at high risk of retiring prematurely.

The potential consequences of the hypothetical withdrawal of 20 GW of nuclear capacity include: 1) a ~3.2% increase in carbon emissions if replaced by gas-fired units or 2) a significant increase in cost if replaced by renewables.

Without a carbon price, out-of-the-market payments would be needed to effectively maintain merchant nuclear capacity. Filling the revenue gap would come at a fleet-average cost of $3.5-5.5/ MWh for these plants, which is much lower than the cost of subsidizing wind power. The policy support could take the form of direct zero-emission credits, renewable portfolio standard expansion, or clean capacity market mechanisms. As a last resort, the exercise of a new mothballing status could prevent the irreversible retirement of nuclear power assets.

Highlights:

- 2/3 of the U.S. nuclear capacity are unprofitable, and 1/5 are likely to retire early
- Cheap natural gas is the primary driver of nuclear's loss of competitiveness
- Zero-emission attributes of nuclear are not valued by deregulated electricity markets
- Supporting existing nuclear is a cost-effective option to lower CO_2 emissions

Keywords: nuclear, deregulated market, retirement, mothballing, zero-emission credit, carbon

1. Introduction

In 2015, nuclear represented 20% of the total U.S. electricity generation and 60% of the country's carbon-free electricity (EIA, 2016). With a total installed capacity of 104 GW, the reactor fleet reported a record high 92.5% capacity factor (NEI, 2016). Almost all reactors have been granted a 20-year license extension from 40 to 60 years by the Nuclear Regulatory Commission (NRC, 2016).

Despite this consistently positive performance, in the past three years five nuclear power plants, totaling 4.7 GW of installed capacity, retired from the electrical grid before the end of their operating license. Eight additional ones have officially announced their retirement in the coming years (see Table 1), and many more are at risk of retiring prematurely according to studies by Steckler (2016) and Rorke (2016). Low historical and forward electricity and capacity prices, together with relatively high long-term operating costs, make nuclear plant

[*] Corresponding author. *E-mail address:* gharatyk@mit.edu.

operation unprofitable in many locations. Even plants owned by public power utilities or rate-of-return regulated utilities have started to shut down (case of Fort Calhoun in 2016).

Table 1 – Executed, contingent, or planned nuclear retirements in the United States as of January 2017.

	Plant name	**Year**	**Retirement age (yr)**	**Capacity (MW)**	**Market**
Retirement executed	Crystal River	2013	36	877	South East
	San Onofre	2013	30	2,150	CAISO
	Kewaunee	2013	39	574	MISO
	Vermont Yankee	2014	42	619	New England
	Fort Calhoun	2016	43	478	SPP
Retirement planned but may be overturned by policy intervention (subsidy)	Clinton	2017	30	1,078	MISO
	Quad Cities	2018	46	1,819	PJM
	Fitzpatrick	2017	42	853	NYISO
Retirement announced	Palisades	2018	47	820	MISO
	Oyster Creek	2019	50	637	PJM
	Pilgrim	2019	47	685	New England
	Indian Point	2020-21	45/46	2071	NYISO
	Diablo Canyon	2024	39	2,240	CAISO
	Total			14,901	

In this paper we first provide an updated assessment of the economic viability of the U.S. nuclear plants (Section 2). We then study the levers of profitability to explain why retirements occur (Section 3) using a wholesale electricity market model. In Section 4 the potential consequences of the closures are presented. In the last section, we discuss a set of regulatory options to the industry and policy-makers to prevent or mitigate the negative impacts identified.

This paper contributes to the existing literature in several ways. First, it provides an analysis of nuclear power plant closures. Many papers have focused on *new* nuclear and its benefits for climate policy and economics (Joskow and Parsons, 2009, Deutch et al., 2009, Joskow and Parsons, 2012, Linares and Conchado, 2013, Harris et al., 2013). However very few have focused on the prospects for *existing* plants, as well as on the causes and the policy consequences of nuclear power plant closures. The recent paper by Davis and Hausman (2016) is an exception. The authors quantify the consequences of the closure of the San Onofre Nuclear Generating Station in California using econometric techniques. Their analysis, though, is limited to California and to a past decision. They do not look at the nation-wide picture nor at the prospects. Other papers, mainly from the banking and financial service industry, have looked at the financial health of the U.S. nuclear reactor fleet and created forecasts on future retirements (Steckler, 2016, Rorke, 2016), but they lack long-term policy analysis and rigorous model description. More recently, the nuclear community investigated the topic of early nuclear retirements and issued policy recommendations (DOE/INL, 2016, ANS, 2016). This paper completes their profitability estimates with more precise cost and revenue data. Finally, we try to discuss policy options that are innovative and/ or have not been quantitatively evaluated. The reconciliation of competitive markets with environmental considerations is a common topic in the literature (IEA, 2016) but few studies have assessed its impact on the competitiveness of nuclear power specifically (OECD-NEA, 2011, Kee, 2014, 2015, 2016). Our discussion about the efficiency of regulatory measures in preserving nuclear power in competitive markets aims at filling this gap.

2. Profitability Outlook for U.S. Nuclear Plants

What is the extent of the financial troubles of the U.S. nuclear power plants? This section provides an estimate of the past, present and future profitability of every single plant in the country. The assessment is based on public data, i.e. published prices and costs. Bilateral power purchase agreements, which are usually confidential, and unforeseen expenditures are absent from the revenue estimate. Although bilateral purchase contracts can delay the retirements of assets, we can reasonably assume that in the long run the re-negotiated price of these contracts match the price listed on the exchange market.

2.1. Methodology

The profitability of the 60 U.S. nuclear plants is defined in this section as the net pre-tax earnings of the individual facilities. For any given year, the profitability is the sum of a) the energy sales, b) the capacity market revenue, c) the policy support (subsidies if applicable) minus d) the cost of generation. Both historical (from 2013 until 2016) and future (2017-2019) earnings are estimated. The spreadsheet for the calculation can be accessed online on the MIT CEEPR website[1].

The historical generation of each facility in MWh is obtained from EIA survey forms 923 (2016). For future estimates, we take the average over the 2012-2015 period (4 years, ~2.7 fuel cycles).

The power sales are approximated as the product of the yearly average of the day-ahead[2] Locational Marginal Price of wholesale electricity (LMP, in $/MWh) at the plant location, and the total generation for the time period considered. The hourly historical LMPs come from the market operator (ISO) websites when such an organization exists. The name of the nodes are extracted from the SNL mapping tool (SNL, 2016).

For future LMPs, we summed the nearest hub forward price and the historical spread between hub and LMP at the plant location. The forward price is the “fair value price” of electricity given by Bloomberg and retrieved from a Bloomberg terminal. These forward values exist for every month in the future and for every major electricity hub of the United States. Bloomberg indicates that they are “calculated through a proprietary model that uses future prices, historical spreads, spot prices and other factors”. The historical spread is the average over the last two years, which is long enough to smooth seasonal variations but short enough to incorporate recent structural changes in the locational price signals (caused by the recent large introduction of renewables and associated flow congestion in some areas for instance – see

Figure 1).

[1] ceepr.mit.edu

[2] Except for ERCOT where the real-time LMP is used in lieu of the day-ahead LMP.

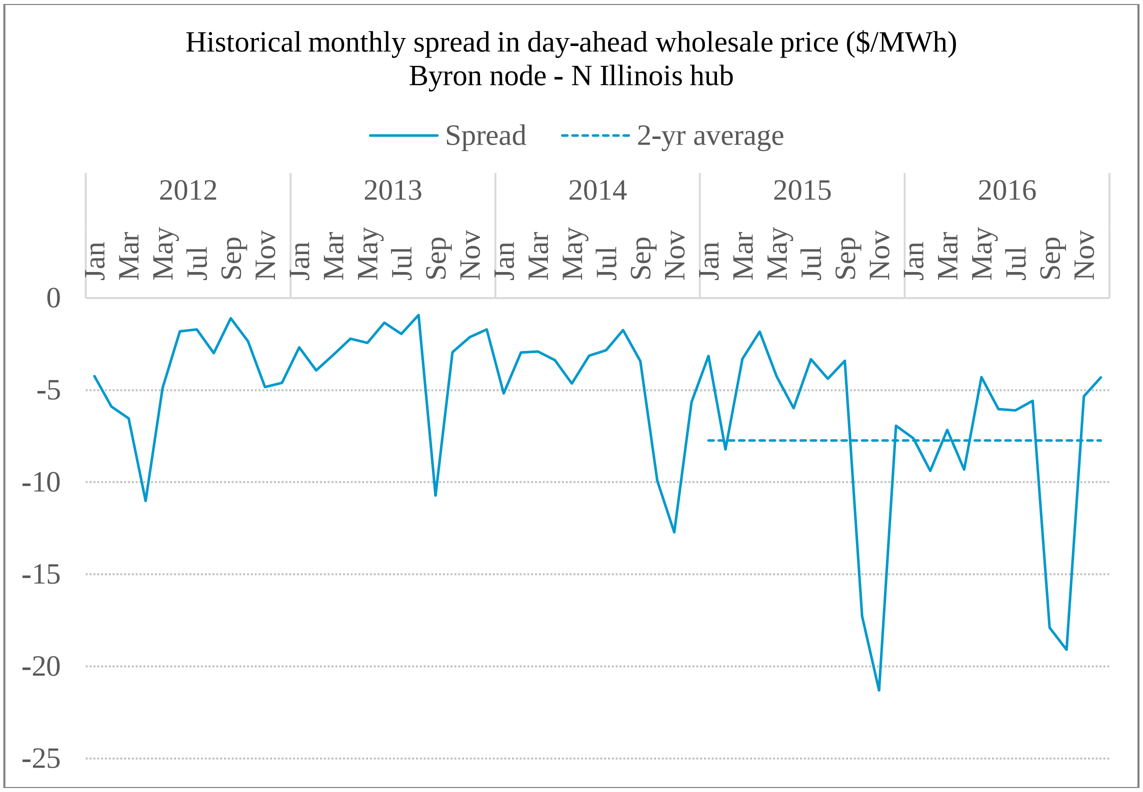


Figure 1. The spread in day-ahead price can be significant and evolves with time due to congestion between nodes. This study takes the last 2-year average spread for projections into the future. In Byron (IL), the spread in the Fall season seems to result from a combination of high wind energy production and low electricity demand in West Illinois, as well as limited transmission capacity to the Chicago hub.

In the "cost-of-service regulated" Southeast of the country, in the absence of an ISO, the bilateral contract values of day-ahead electricity price in the Southern and Florida "hubs" are used in lieu of the LMP. These historical values are reported by Platts and SNL. The price index is therefore similar for all the nuclear plants in the zone (15 plants, 28GW of capacity) and is less granular than in the other U.S. zones. The forecasted price is the sum of the closest hub – Indiana – forward price and the historical spread between this hub and the zones.

Capacity market revenues are known once capacity auctions have been cleared. Preliminary auctions results when they exist are used to forecast future capacity revenue (PJM, ISO-NE, NYISO and California). For MISO, where preliminary auctions do not go as far into the future, we extrapolated the latest capacity market result.

The policy support is the potential subsidy that the plants receive for their zero-carbon attribute. If confirmed, these subsidies will apply to 5 plants in the US, in the form of Zero Emission Credits (ZEC): Nine Mile Point, Fitzpatrick and Ginna in New York and Clinton and Quad Cities in Illinois starting in 2017.

Finally, the cost of generation is taken from the SNL Financial database (2016). SNL provides plant-specific estimates of annual generation cost, based on IEA, FERC, and RUS survey forms (which include fuel cost reporting in particular) and/or a proprietary model when the data are incomplete. The SNL model is based on a three-year regression of a "large enough sample". The regression formula is based off net generation, age of plant and operation capacity. The total cost comprises fuel, fixed operation and maintenance as well as non-fuel variable operation and maintenance cost. Note that the initial capital expenditure of the plant construction is a sunk cost. The fleet-average cost of generation closely matches the number disclosed by the industry (see NEI 2016 and Table 2). The O&M cost of future years is simply the O&M cost of the latest year augmented by the expected inflation.

Table 2 – The plant-average cost of generation from SNL is lower but close to the one reported by NEI

	2012	2013	2014	2015	Unit
SNL estimates (61 plants)	**34.1**	**33.4**	**34.4**	**33.9**	**$/MWh**
[standard deviation]	[5.3]	[6.4]	[6.5]	[4.6]	$/MWh
NEI (reported fleet average, in 2015 $)	39.7	36.9	36.4	35.5	$/MWh
adjusted to nominal $	38.5	36.3	36.3	35.5	$/MWh

2.2. Results

Results were obtained for the 60 operating U.S. nuclear plants existing as of January 2017, regardless of whether they are located in regulated or deregulated market environments. The precision of the estimates varies. In particular the 15 plants located in the Southeast are subject to imprecision due to the coarse assessment of future bilateral contract prices of electricity.

The plant-by-plant analysis reveals profitability in the range of -$29 to +$15 /MWh generated over the 2017-2019 period (Figure 2). The number represents a crude average; no discount factor was applied. Prairie Island and Monticello in Minnesota appear to be the least profitable plants by far, due to low wholesale price in North-West MISO and low capacity factor (80-82%). Most of the Southeast plants show a negative outlook due to their larger cost of production.

Results show that 35 plants, totaling 58 GW of capacity, are out-of-the-money over the 2017-2019 period. When adding the 5 plants – 6 GW – that have announced their retirement, nearly two thirds of the U.S. nuclear fleet display negative outlooks (Figure 2).

The “merchant” plants – the plants that solely rely on markets for their revenue – are of course more exposed and have a higher risk of shutting down prematurely than those owned by a regulated utility or a public power company. As a matter of fact regulated utilities are remunerated based on their cost-of-service and are largely protected from direct market forces. Public power companies (TVA, Energy Northwest, etc.) are also expected to respond with less pressure to short-term market signals (Kee, 2015). We expect most of the plants owned by regulated or publicly-owned utilities to remain in operation. Figure 3 shows the profitability outlook by ownership structure. 12 GW of uncompetitive nuclear capacity is in the “merchant” category and is at high risk or retiring in the coming years.

We recognize that the final decision to retire an individual plant does not solely depend on its expected net pre-tax earnings over the next three years[3]. Nevertheless we consider the aggregate number to be a good indicator of the risk of premature nuclear capacity withdrawal under the current price trajectory.

[3] Other factors need to be considered such as medium- to long-term market conditions, and uncertainty related to all these future cash flows.

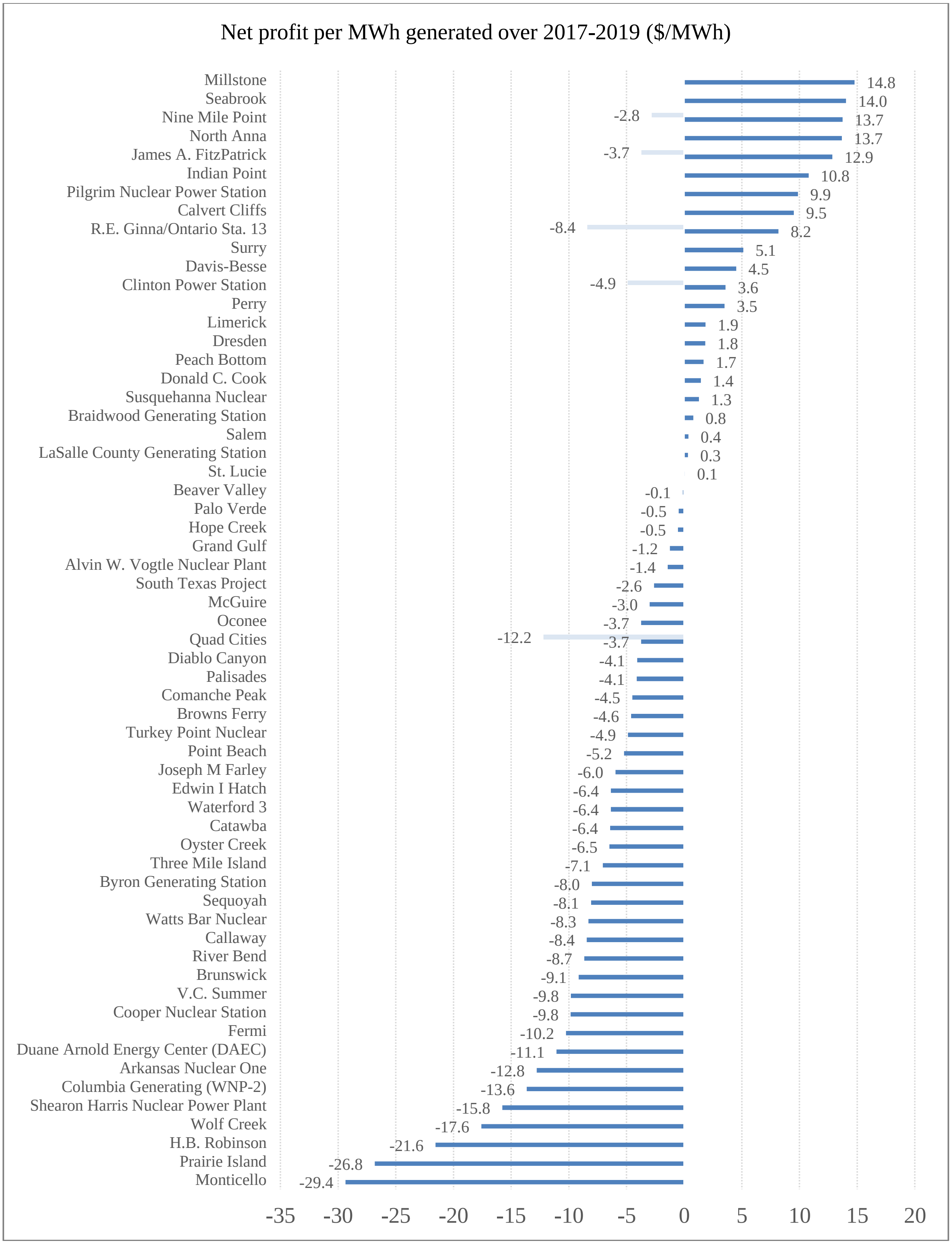


Figure 2. The profitability of the 61 U.S. nuclear plants studied ranges from -$29 to +$15 /MWh over the 2017-2019 time period. The subsidies (ZECs) are accounted; the lightly shaded bars represent the hypothetical profitability of the plants if ZECs were removed.

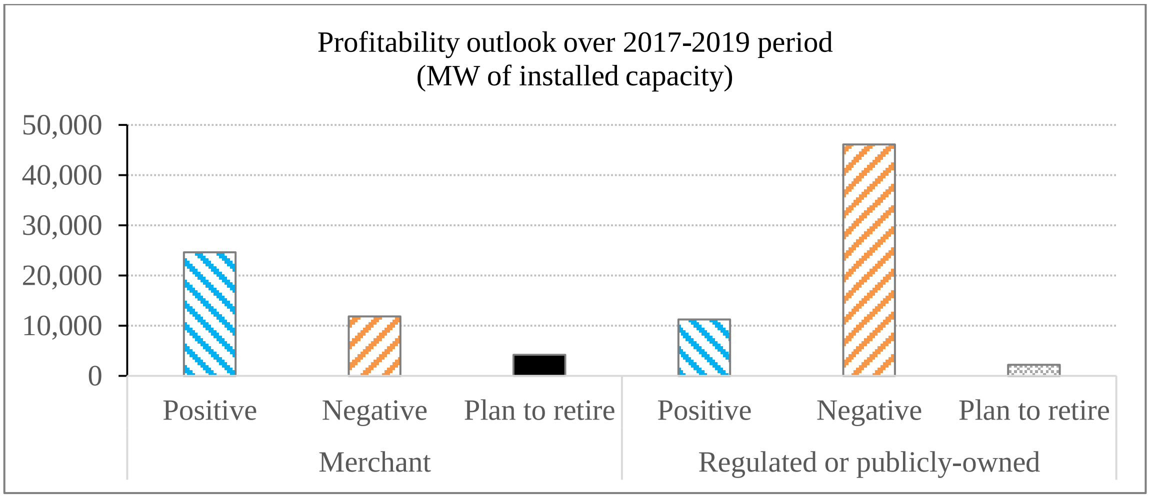


Figure 3. Market signals indicate that the majority of the 100 GW nuclear fleet is unprofitable in the near future. 39% of the merchant capacity is on a path to retirement. The plants owned by regulated- or public power utilities are to a large extent protected from market forces. Note that recently-voted-on state subsidies are accounted.

The breakdown by region reveals strong discrepancies (Figure 4). The Midwest, California and Texas regions are particularly unprofitable for merchant nuclear over the four-year period. PJM displays a mixed outlook, whereas New York and New England are favorable. The next section analyzes why and how these differences arise.

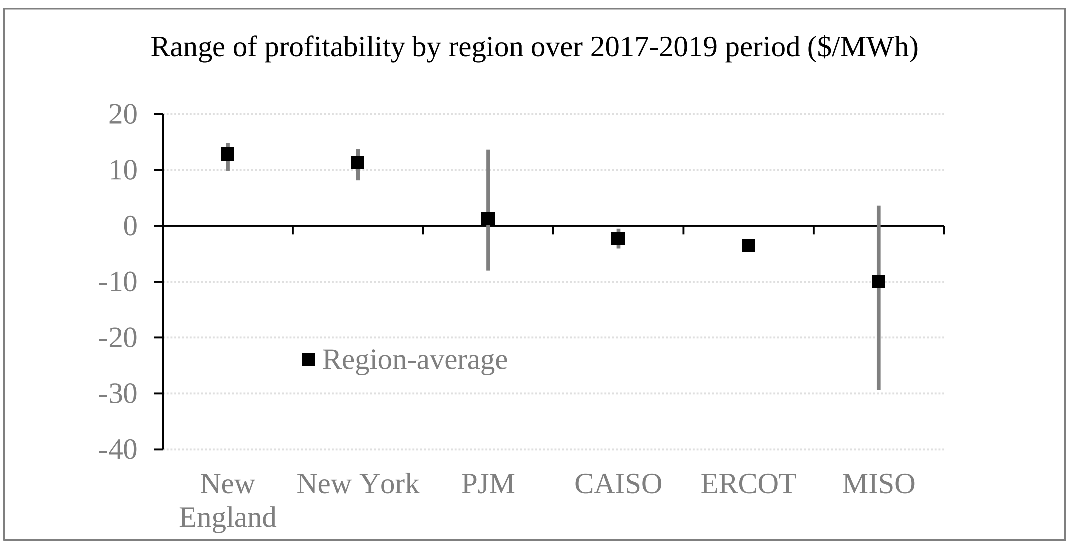


Figure 4. The Northeast markets are more favorable environments for nuclear power plants due to higher wholesale electricity market prices. By contrast, the Midwest, California and Texas markets are challenging.

Table 3 shows the yearly revenue gap for the plants in distress out of the 60 plants studied (retired plants as of January 2017 are not accounted). The numbers for merchant plants are also shown separately. The total number of struggling plants varies from year to year and peaks at 52 in 2016, a particularly challenging year for nuclear. The future is uncertain but forward markets seem to indicate a price recovery. Still, about 35 plants – 55 GW – are durably uncompetitive. The average revenue shortfall for these plants is about $5.5-7 / MWh per year over 2016-2019. This number can be viewed as the minimum amount of policy support that would be needed to bring them breakeven financially.

Table 3 – The average revenue shortfall for the plants in financial distress ranges from $5.5-7 / MWh per year, for a sum of $2.5-3.5 billion/ year. For merchant plants, the range is $3.5-5.5 / MWh and adds up to $00.7 billion / year.

		2013	2014	2015	2016	2017	2018	2019
TOTAL U.S.	**Unprofitable plants**	29	9	37	52	36	38	43
	Capacity (MW)	42,378	8,533	59,282	87,347	57,557	61,867	73,517
	Total revenue gap (M$)	(1,466)	(582)	(2,943)	(5,103)	(2,604)	(3,173)	(3,562)
	Average loss in $/MWh	-4.57	-9.29	-6.29	-7.53	-5.87	-6.66	-6.29
MERCHANT DEREGULATED	**Unprofitable plants**	8	0	11	2	10	10	14
	Capacity (MW)	13,480	-	17,902	39,377	17,794	16,088	27,738
	Total revenue gap (M$)	(212)	0	(670)	(1,579)	(372)	(536)	(762)
	Average loss in $/MWh	-3.83	0	-5.83	-5.05	-3.24	-5.27	-4.37

3. Drivers of Un-Competitiveness in Deregulated Markets

The economics of nuclear power in competitive environment have been deteriorating. As seen previously the revenues from the wholesale and capacity markets are often not sufficient to cover the cost of electricity generation. In this section, we analyze the fundamental sources of change that drive down the competitiveness of nuclear. Electricity generation revenue comes from several sources, namely: supplying electricity (kWh); assuring electricity generating capacity on demand (kW); and providing grid ancillary services.

3.1. Wholesale Price of Electricity

As displayed in Figure 5, the wholesale price of electricity has been declining everywhere in the United States since the years 2007-08. This phenomena has directly impacted nuclear power plants, which supply base-load electricity and for which the wholesale market is the primary source of revenue. In fact, the sales of electricity represent >90% of the revenue of the U.S. nuclear plants. This ratio is larger than for coal and natural gas power plants, for which capacity markets and ancillary services represent a larger share of revenue.

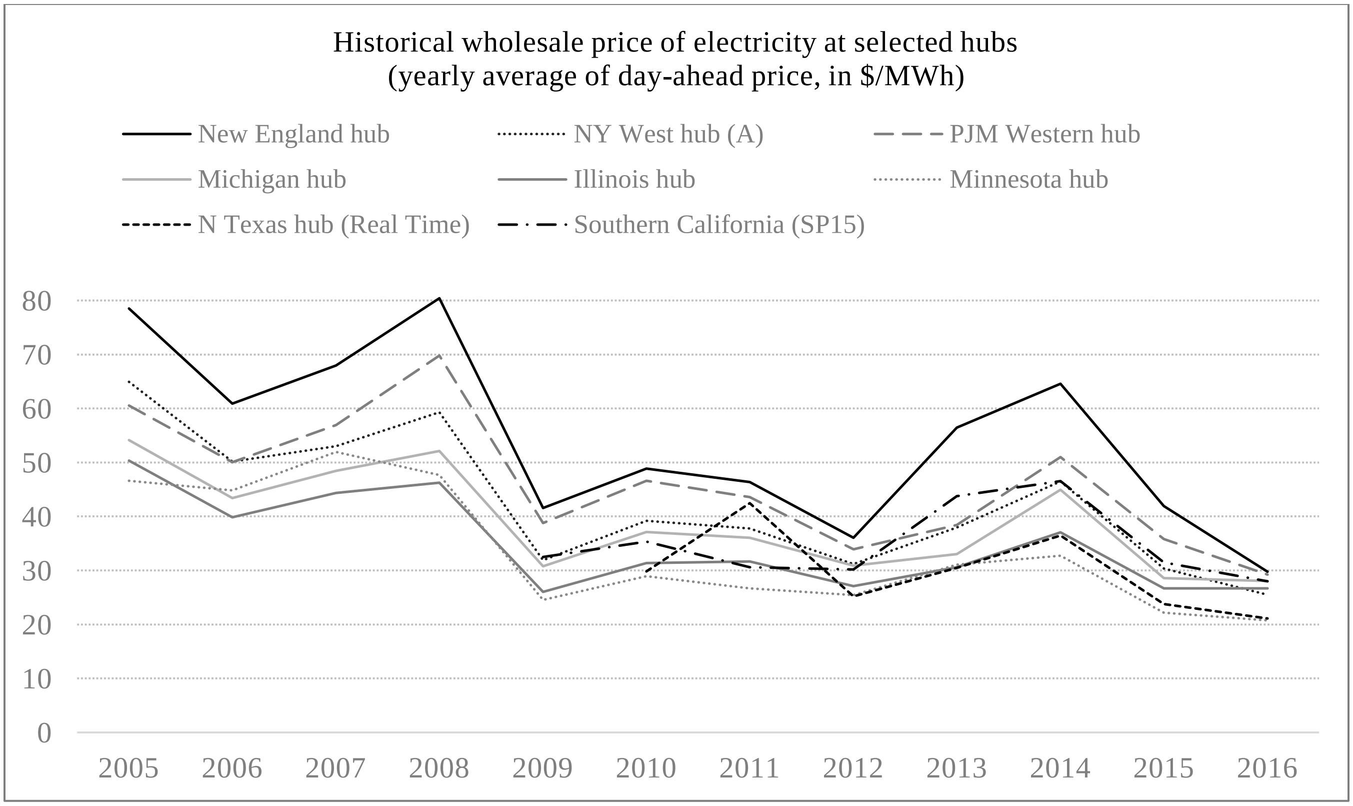


Figure 5. Wholesale price of electricity have gone down everywhere in the United States in the past decade.

To better understand the reasons for the price decline, we propose replicating the price formation of wholesale prices in two zones relevant for nuclear plants: the Midwest and the Mid-Atlantic region, which total 50 GW of nuclear capacity. We compare the years 2008 and 2015 and analyze the single structural changes affecting price and the magnitude of their impact.

3.1.1. Model of wholesale electricity market

The wholesale price of electricity is simulated with a simple economic dispatch model of the generators in the zone spanning one year (8760 hours). The model takes the hourly demand for electricity, the generation profile of renewables (wind), the installed generation capacity, and its short-run marginal cost in order to dispatch the generation and meet the demand at minimal cost. The price of electricity for each hour is determined by the marginal unit that serves the load. The transmission line constraints inside the zone are ignored, as well as the transmission losses (single node approximation), and the power exchanged with the neighbouring regions is treated as an addition (export) or reduction (import) of the total demand for the zone. The constraints introduced in the optimization problem are: the load demand constraint, the constraints on the maximum output of each generator, and the flexibility constraint (ability to power up and down each generator). The cost of not meeting the demand is equal to the value of lost load, which is set at $500/MWh.

The formulation of the problem leads to the solving of a linear optimization problem, which is faster to compute than if binary constraints had been introduced. The generators of a given class are aggregated when their characteristics are similar. The model formulation as well as the cost and technical assumptions for the generators are listed in Appendix A.

3.1.2. Results: Midwest region (IA, IL, IN, MI, MN, MO, ND, WI)

The first region of interest is the Midwest, defined here as eight states together: Iowa, Illinois, Indiana, Michigan, Minnesota, Missouri, North Dakota and Wisconsin. Nuclear plants in this region are particularly affected by low wholesale prices. In Minnesota, average day-ahead hub prices were as low as $22.2 / MWh in 2015. Despite its simplicity, our model reproduces fairly well the observed wholesale prices as well as their relative drop between 2008 and 2015 (Table 4). To do so, it is essential to correctly model the coal-fired power plants in the region since they dominate the installed capacity (44-49% of all capacity). The model is very sensitive to their heat rate and availability. See Appendix A for more details.

Table 4 – Actual vs. computed annual wholesale price in the Midwest region ($/MWh)

Hub name	**2008**	**2015**	**Delta 2008-2015**
Illinois hub	46.2	26.7	-42%
Michigan hub	52.1	28.6	-45%
Minnesota hub	47.7	22.2	-53%
Midwest model	**42.4**	**26.9**	**-36%**

The region has seen important structural changes from 2008 to 2015, specifically:

- Addition of 12.8 GW of wind power capacity, which added up to 9% of the total electricity supply in 2015.
- Decrease of natural gas price from $9.3 to $3.2 /MMBtu, and increase of coal price from $1.45 to $1.85 /MMBtu (EIA, 2016).
- Reduction of total electricity demand by 3.8%. Most of this change (3.3% out of 3.8%) was caused by a reduction in electricity exports[4].
- Retirement of 4.5 GW of coal power plants.

To quantify the effects on price caused by each of these factors, we employed our wholesale electricity model. Starting from the 2008 conditions, we replaced the inputs once-at-a-time by their 2015 value, and then reported the effect on price. Note that due to the non-linear nature of the wholesale market model, the sum of the effects does not equal the effect of their combination. The separate and combined price effects are reported in Figure 6.

[4] Net imports are calculated as the sum of the net interstate imports for each states reported by the EIA. The total demand is equal to the total supply in the zone. The “internal” demand is defined as the difference between the total demand and the net exports of electricity in the zone.

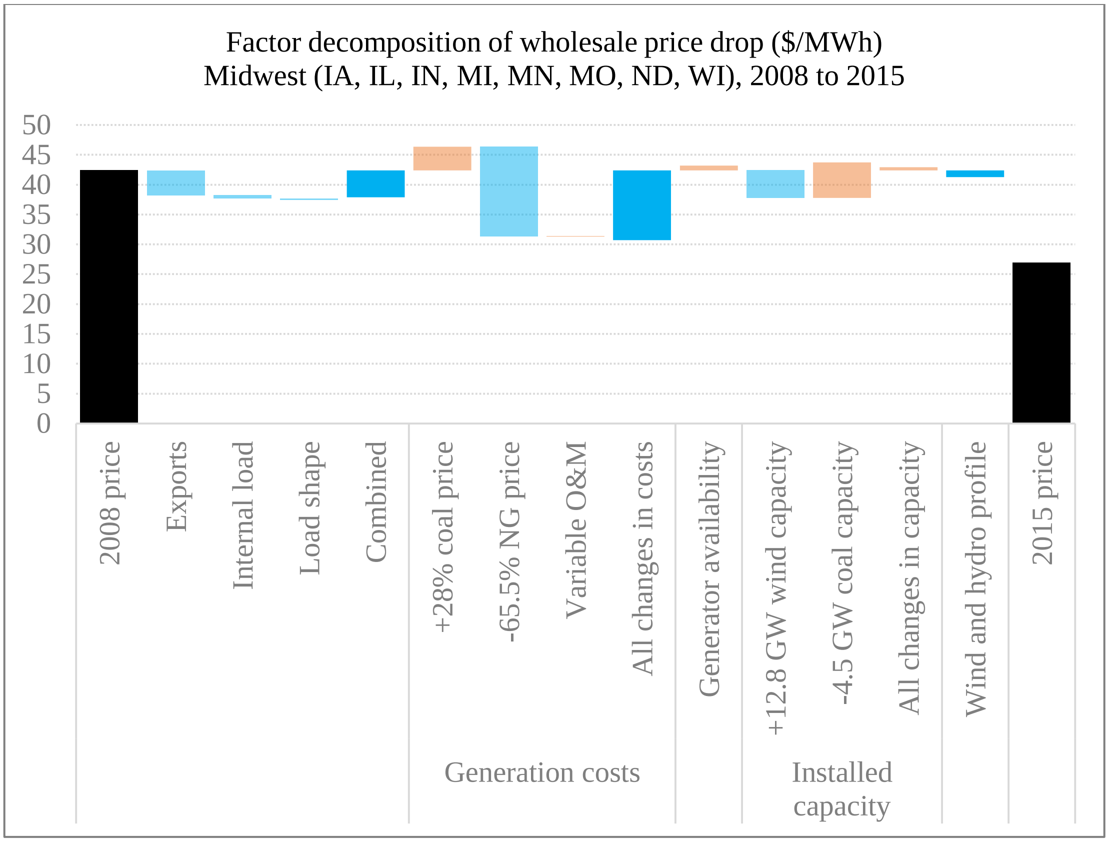


Figure 6. The primary drivers of the price collapse in the Midwest are the decline in load demand and the collapse of natural gas prices. The effect of increased wind capacity is offset by the retirement of coal power plants over the same period.

In the Midwest, despite natural gas price collapse, production costs from coal-fired generators have remained cheaper than from Combined-Cycle Gas Turbines (CCGTs). The merit order of generation resources has stayed mostly the same in the supply curve. However, the drop in marginal cost of production for gas-fired units due to cheap natural gas has been the primary cause of wholesale price contraction. The diminution in total electricity demand – and in exports in particular – has been the second most significant contributor. More surprisingly, the large introduction of renewables (wind) had a relatively small effect on price (-$4.6/ MWh). It was completely offset by the retirement of coal-fired generators (+6.0/MWh). The effect of wind capacity introduction might have been more severe at the nodal level, but our zonal market model did not capture these local effects.

3.1.3. Results: Mid-Atlantic region (DC, DE, KY, MD, NJ, OH, PA, VA, WV)

The Mid-Atlantic region (D.C., Delaware, Kentucky, Maryland, New Jersey, Ohio, Pennsylvania, Virginia and West Virginia) is another relevant region due to its high concentration of nuclear power plants (23 GW of capacity installed, 23% of the U.S. fleet). It is also the region that hosts the Marcellus shale gas deposit, whose exploitation has led to the dramatic boost in domestic natural gas production and associated price disruption between 2008 and 2015.

Nevertheless, the abundance of cheap natural gas has not yet materialized in electricity cheaper than in the Midwest, as can been observed in Table 5. Electricity prices were still $3 to $16/ MWh more expensive than in the Midwest in 2015. Our model replicated these wholesale prices in a satisfactory manner again; they lie in the range of the historical hub prices. For this region, the model is very sensitive to both coal- and gas-fired generator assumptions. These assumptions are reported in Appendix A.

Table 5 – Actual vs. computed annual wholesale price in the Mid-Atlantic region ($/MWh)

Hub name	**2008**	**2015**	**Delta 2008-2015**
PJM Western hub	69.8	35.8	-49%
AEP Dayton hub	53.2	31.5	-41%
Dominion hub	73.5	38.2	-48%
Mid-Atlantic model	**59.4**	**31.8**	**-46%**

The Mid-Atlantic zone saw the same list of structural changes as the Midwest, although their magnitude is different:

- Addition of 1.8 GW of wind power capacity, a very moderate amount compared to the Midwest.
- Decrease of natural gas price from $10.3 to $3.2 /MMBtu, and increase of coal price from $3.3 to $3.4 /MMBtu (EIA, 2016). These relative changes are explained by the fact that the region sits on the newly-exploited Marcellus gas deposit and is farther from the Powder River and Illinois coal deposits than the Midwest.
- Reduction of total electricity demand by 8.3%. The internal load demand dropped by 12.1% but the region imported less electricity, which alleviated the effect on price (when the local producers clear more generation, the locational marginal price of electricity increases).
- Retirement of 16 GW of coal power plants, and addition of 13.1 GW of new gas-fired power plants.

The price decomposition of these individual factors is shown in

Figure 7. It follows the same methodology as for the Midwest price decomposition.

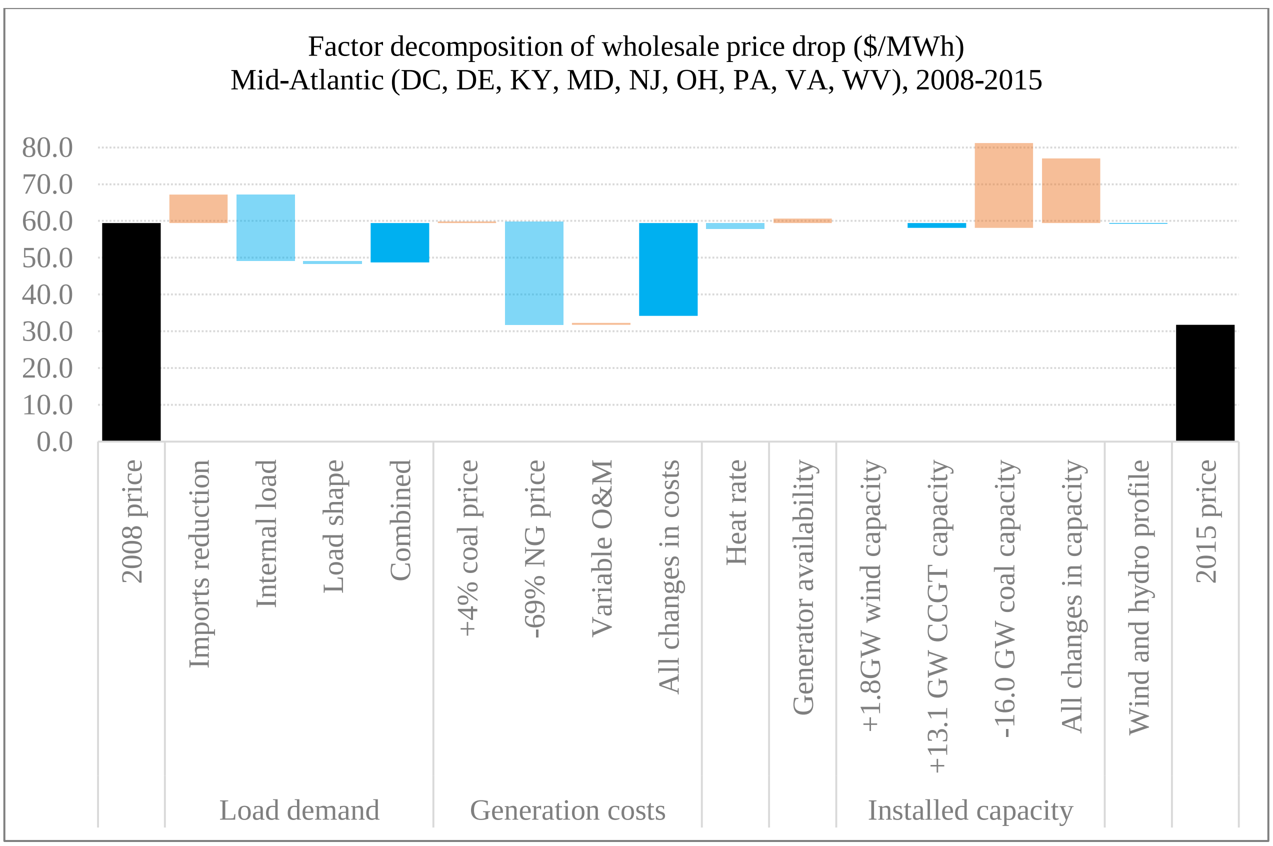


Figure 7. The primary drivers of the price collapse in the Mid-Atlantic are the collapse of natural gas prices and, to lesser extents, the drop in load demand and the change in capacity mix. The replacement of base-load coal-fired plants by base-load CCGT units yields a greater exposure to natural gas price.

As expected, the change in load demand had a more moderate impact in the Mid-Atlantic than in the Midwest. Natural gas price collapse had the largest single effect (-$28.1/MWh). Not only did it decrease the cost of generating electricity, but it changed the merit order of the technologies in the supply stack. Figure 8 shows that CCGT units displaced coal as the source of base-load electricity, forcing a large number of them to retire. If natural gas prices were to increase, the situation could revert and price could spike to high levels again. The retirement of coal-fired units makes the Mid-Atlantic market more sensitive to natural gas prices than in 2008, as demonstrated by the +$17.6/ MWh effect on price which would occur if 2008 natural gas prices were to return.

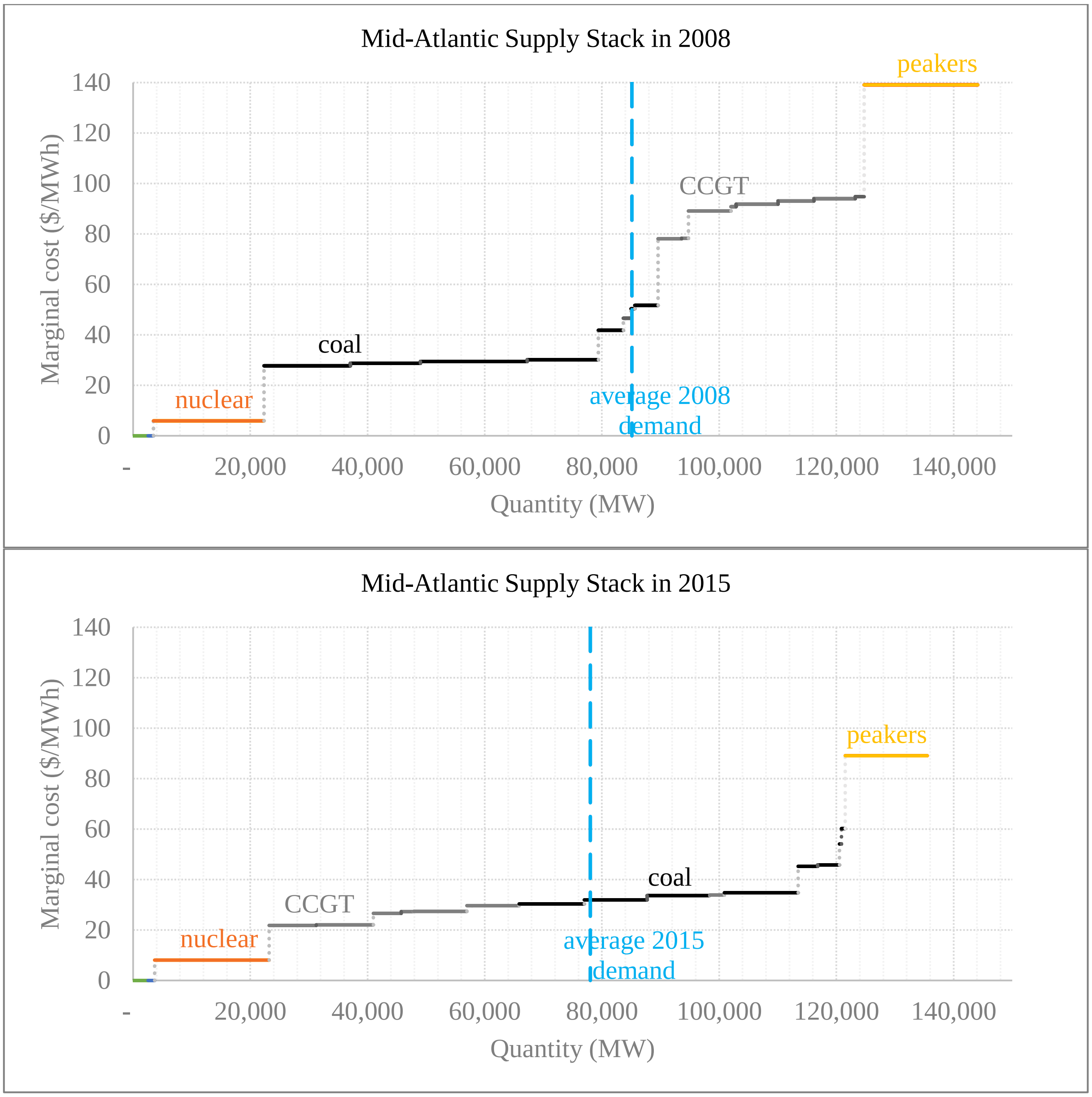


Figure 8. In the supply stack of 2008 (top), CCGT units are more expensive to dispatch than coal-fired units. In

2015 (bottom), the situation has been reversed and coal is being displaced by CCGT.

3.1.4. Perspectives on future wholesale prices

Since natural gas price is the major agent of change in the wholesale power market, it is legitimate to wonder if its current low price is expected to last or not. Unfortunately for nuclear generators, and fortunately for consumers, natural gas is expected to remain cheap. Figure 9 shows the current "market view": albeit recovering slightly, natural gas prices do not reach their pre-2008 levels in the short- and medium term.

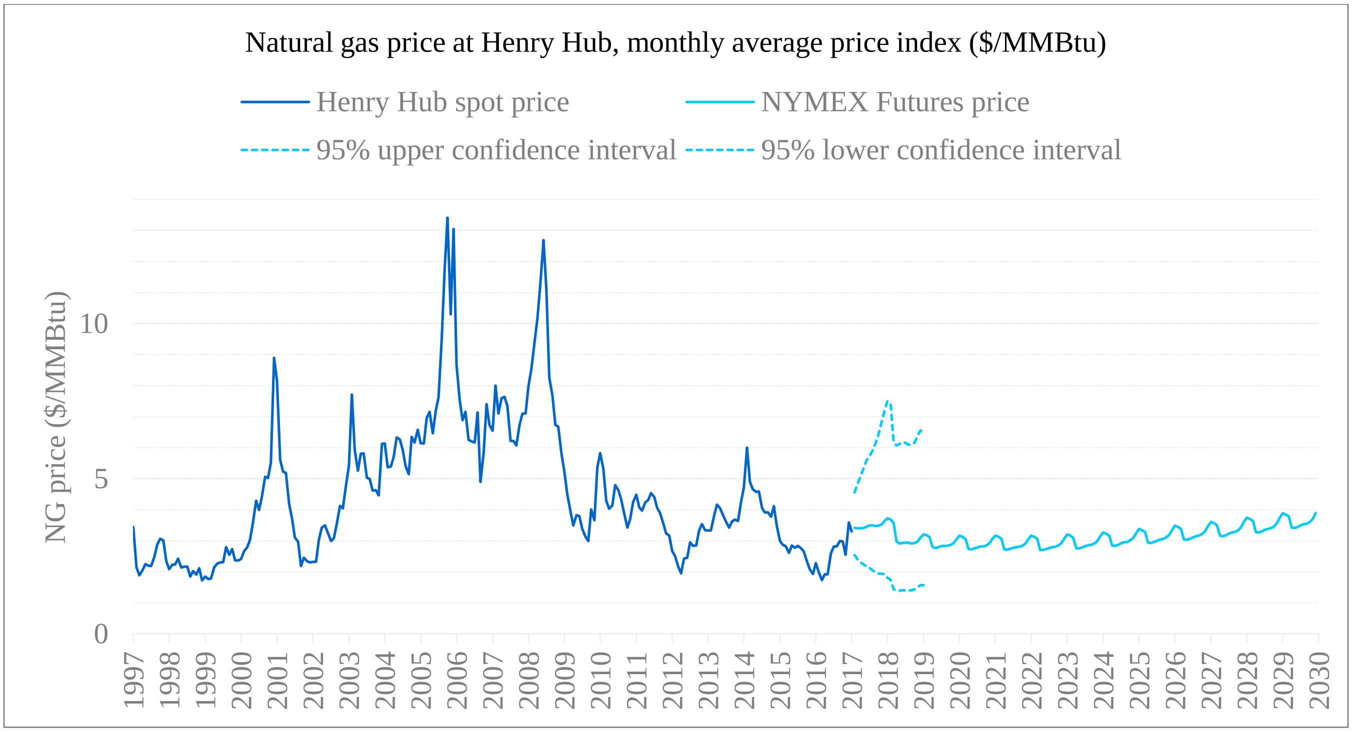


Figure 9. Forecasts based on raw futures prices indicate that natural gas prices remain low in the near- and medium-term (plot as of mid-January 2017). The 95% confidence interval displays significant uncertainty. It is calculated according to the EIA methodology which is based on the implied volatility of financial options traded on the market (EIA, 2009).

How do natural gas prices translate into wholesale electricity prices? In Figure 10, we run simulations and plot the average wholesale price as a function of natural gas price in the Mid-Atlantic and Midwest regions, keeping all the other parameters (load demand, installed capacity, coal prices, etc.) identical to their 2015 values. In the simulation, we assume that all the gas-fired plants see the same natural gas price uniformly. Natural gas price changes the cost of generation but also the dispatch of the generators. We observe that the coal-to-gas dispatch transition occurs between $3 and $6/ MMBtu for the Mid-Atlantic, and below $5/ MMBtu for the Midwest. The Mid-Atlantic region exhibits a stronger sensitivity to natural gas price due to its high concentration of gas-fired plants. The possible massive replacement of nuclear plants by CCGT units would intensify this sensitivity even more.

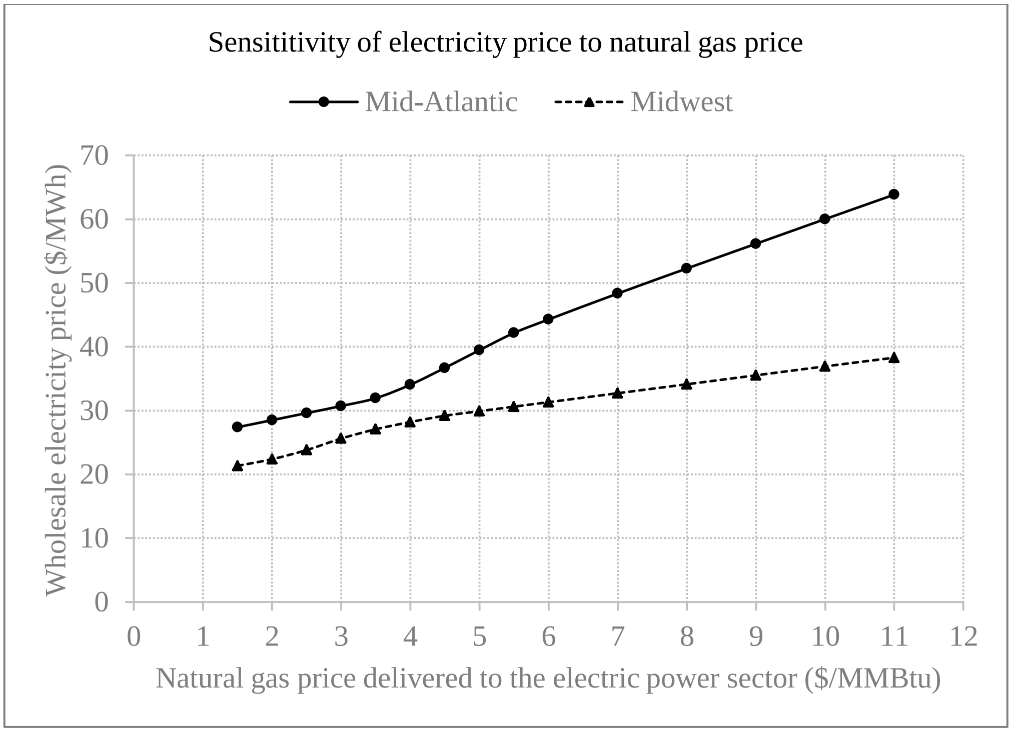


Figure 10. The simulations show that the Mid-Atlantic zone is more sensitive to the price of natural gas than the Midwest due to the former's higher concentration of gas-fired power plants. The retirement of nuclear plants and their replacement by gas-fired units would intensify this dependence and sensitivity.

With natural gas price not exceeding $4/MMBtu, wholesale electricity market spot prices will not go beyond $35 and $30/ MWh in the Mid-Atlantic and Midwest. The wholesale market will most likely continue to provide low revenue for nuclear plants in the medium term. Therefore, saving the nuclear fleet requires other levers.

3.2. Cost of nuclear power generation

The cost of electricity generation from existing nuclear plants averaged $35.5/MWh in 2015 (NEI, 2016). This includes annual capital expenditures (equipment replacement and upgrade), operation and maintenance (O&M), and fuel. Unlike generators running on fossil fuels, a large share of the expenses are "fixed" and do not depend on the electricity output. For instance, the number of security personnel (around 5% of the total cost) is set by the regulator and is incurred whatever the size or power output of the plant. This characteristic favors large plants: the average cost of generation was $32.9/ MWh for multi-unit plants and as high as $42.5/ MWh for single-unit plants. Single-units plants are the first plants to suffer from low wholesale prices and this is not a surprise that they form the majority of the plants that are expected to retire prematurely (Table 1).

Although relatively high, average generation costs have been decreasing since 2012 (Figure 11). Capital expenditures have been reduced after the 2011-2012 peaks, which were due to post-Fukushima upgrades and license extension programs. More recently, fuel costs have gone down thanks to progress in technology. O&M, the major cost item, remains expensive nevertheless. The industry committed to reduce them by $3.5/MWh from the 2012 level (UBS, 2016). The objective of this initiative called "Delivering the Nuclear Promise" is to achieve $28/ MWh in total generation cost by the end of the 2020's. We quickly see that this initiative will not be sufficient for the single-unit plants, and / or the plants located in regions with wholesale electricity spot prices in the low $20 /MWh range such as the Midwest.

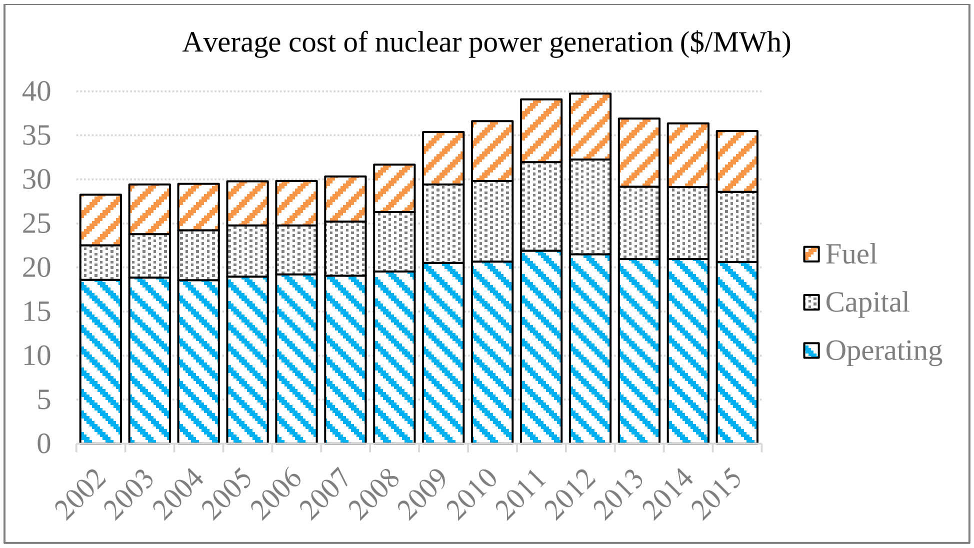


Figure 11. After a peak in 2012 due to large capital expenditures, nuclear power generation costs have been decreasing (NEI, 2016). However, they are still greater than market revenues in many locations. The costs are converted into 2015 $ for comparison.

3.3. Capacity markets

Capacity markets are a secondary but important source of revenue for nuclear plants in regions where capacity markets exist (Figure 12). They can add up $300/ MW-day ~ $14/ MWh to the revenue of the plants in the best case (Pilgrim, 2018). The fleet-average revenue was nevertheless more moderate, between $60 and $80/ MW-day over the last years, i.e. around $3/ MWh. When plants fail to clear the capacity market, they receive zero for an entire year which can precipitate their retirement.

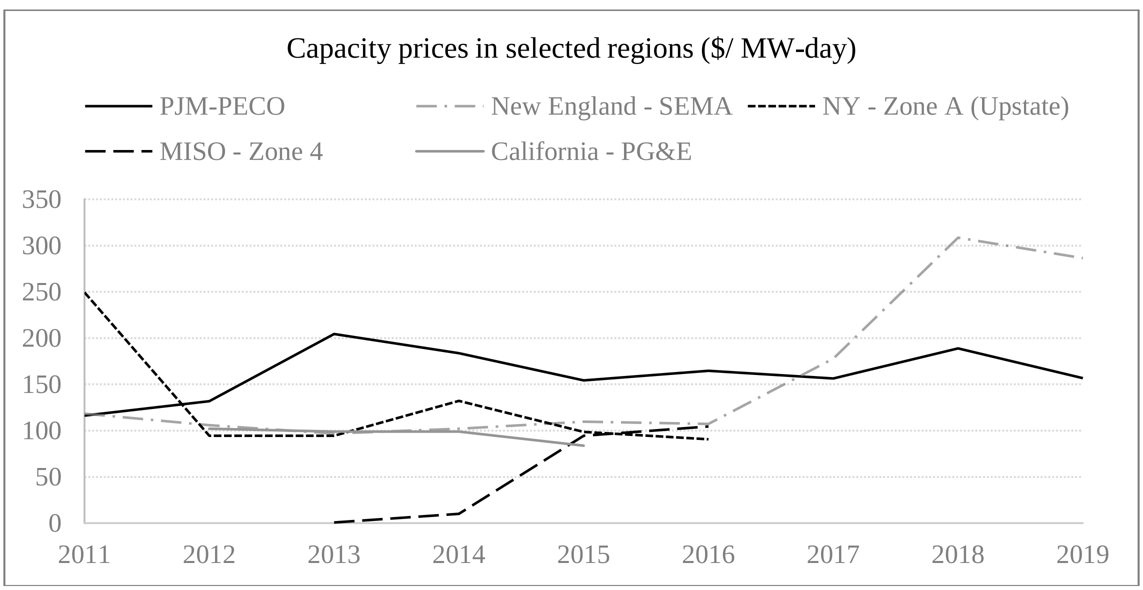


Figure 12. Capacity price differ between regions but in general provide moderate revenue for nuclear plants when these prices exist. The fleet-average price was $60-80/ MW-day over the last years, i.e. around $3/ MWh. Texas does not have any capacity mechanism.

Capacity markets were implemented in the late 2000's, i.e. quite recently in the history of electricity market restructuring. Capacity market design is still evolving. Important reforms were implemented in the Northeast after the polar vortex in 2013-2014 when numerous fossil power plants failed at providing the capacity they promised. More reforms could happen but they are not likely to change the revenue game for nuclear plants due to the relatively low levels of capacity payments.

3.4. Other drivers of retirement: safety and business divestment strategy

Although economics are the origin of most premature nuclear retirements, and the main area of focus of this paper, we should highlight that in some instances non-economic factors are more decisive.

In at least two recent cases – Oyster Creek and Indian Point – safety concerns and the associated cost of compliance with regulation led to the decision to close the facilities. Economics were *not* the primary driver. Indian Point appears for instance very profitable in our analysis of section 2. But political pressure pushed the owner of the plant, Entergy, to announce in January 2017 the closure of the plant, which sits 50 miles away from NYC.

The same owner Entergy also announced the shutdown of Pilgrim in Massachusetts. Similarly to Indian Point, the economics would advocate for continued operation but in this case the business strategy of Entergy is responsible. Entergy decided to divest from merchant nuclear power and entered the process of either selling or closing all its nuclear assets located in ISO markets (K. Maize, 2016).

4. Implications of Premature Nuclear Retirements

What are the consequences of a massive wave of nuclear retirements? This section analyzes the impact of the hypothetical retirement of 20 GW of nuclear capacity, which is about a third of the total U.S. nuclear capacity[5]. Running at 92% capacity factor, 20 GW of nuclear generation represent 161 TWh of zero-emission electricity. Such a large withdrawal impacts environmental policy, electricity price and the natural gas market.

Three scenarios are considered when it comes to the replacement of this nuclear power supply:

- Scenario 1: the retired nuclear generation is replaced by generation from other sources in place. These existing sources, which run on fossil fuel, increase their production to make up for the withdrawal of nuclear capacity and satisfy demand.
- Scenario 2: the retired nuclear generation is replaced by new gas combined cycle plants (CCGT). These modern units have a heat rate of 6,600 Btu/ kWh and an availability factor of 87%.
- Scenario 3: the retired nuclear generation is replaced by renewable generation coming from new wind turbines. In the Midwest, their capacity factor was 39% in 2015.

Although these scenarios are extreme and ignore possible grid-related constraints[6], they have the merit of drawing the boundaries of the possible outcomes resulting from the mix that replaces the retired nuclear assets. Renewables and CCGT are now – and certainly will be – the preferred generators installed in the coming years due to their good economics (Figure 14). The CCGT additions are based on pure market economics while the renewable growth is more dependent on public subsidies. How much of each will be built depends on the market conditions and the policy incentives.

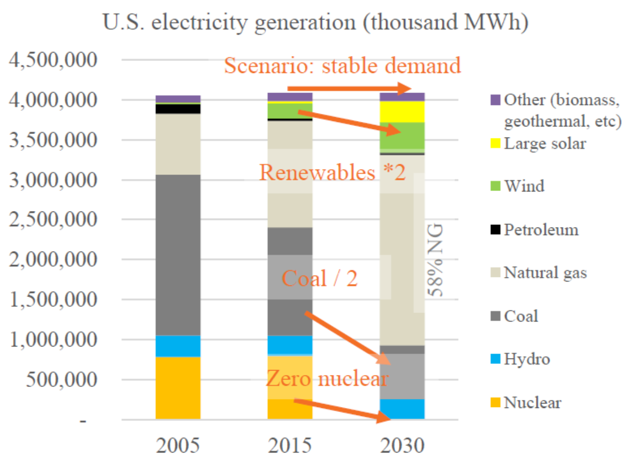
[5] 20 GW roughly correspond to the retirement of the 12 GW merchant plants at risk identified in section 2.2, plus the 6.5 GW of already-announced capacity retirement in Table 1.

[6] From a dispatch point of view, base-load nuclear is not equivalent to intermittent renewables nor flexible CCGT (NECG, 2014).

4.1. Impact on Carbon Emission and Climate Policy

Unless replaced by emission-free hydro or renewable energy, the retirement of nuclear generation from the grid results in a net increase in greenhouse gas emissions. The immediate impact of 20 GW nuclear retirement is an 5.8% increase in CO_2 emissions for the U.S. power sector (carbon intensity of the dispatchable generators times 161 TWh). This would represent a large setback in achieving the objective of 32% emission reduction from the 2005 level by 2030[7].

Is it feasible to reach climate policy objectives without nuclear? Calculations shows that carbon emissions reduction goals could still achieved without nuclear if coal power plants retire massively and are replaced by natural gas and renewables. An example of such a scenario is exhibited in Figure 13. A transition away from coal and nuclear would be politically challenging but could be affordable if natural gas remains cheap and the cost of renewables and energy storage continues to decrease (Lazard, 2016).



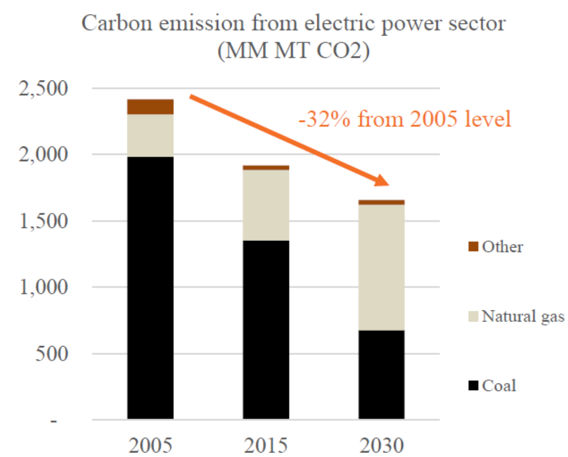


Figure 13. 2030 climate policy objectives could be achieved without nuclear in a hypothetical scenario where half of the coal-fired capacity retires, demand is stable, renewables production expand by a factor 3 and natural gas accounts for the rest (58%) of the electricity generation. Still, nuclear would be essential to meet the 2050 policy objectives.

However, more aggressive goals such as an 80% emissions decrease by 2050 would require full utilization of emission-free resources to eliminate coal power generation and reduce natural gas utilization. Nuclear would prove essential to reach long-term climate objectives.

The cost of carbon damage avoided by 20 GW of nuclear capacity is evaluated to \$4.7 billion / yr – at the current social cost of carbon of \$41.8/MT CO_2 (EPA, 2016) and the 2015 carbon intensity of 0.695 MT CO_2/ MWh for the make-up generation (refer to Table 6 for scenario comparison).

4.2. Short-term Impact on Electricity Price

The immediate retirement of a power plant creates a shift to the left of the supply curve, leading to an upward price shock. However such a case occurs rarely in practice. Instead, retirements are announced years in advance (see Table 1) and the market agents have time to react, for instance by planning the construction of new power plants, by refurbishing old ones, or by postponing the outage and retirements of existing generators. The price shock observed in the real world is therefore less severe than if the plants were to retire overnight, without notice.

[7] Goal of the Clean Power Plan for the power sector.

For the purposes of estimating the upper limit of the price shock, we nevertheless simulated the brutal retirement of 20% of the nuclear capacity in the 2015 Midwest and Mid-Atlantic wholesale market models presented in 3.1.1 and in Appendix A. To meet the electricity demand, the other generators augment their production; this is our scenario 1. The yearly-average price shock is +$0.6 and +$0.9/MWh in the Midwest and Mid-Atlantic respectively. These represent an increase in the cost for the consumers of $410M and $640M/ year in these two regions.

4.3. Long-term Impact on Electricity Price

The long-term impact on price resulting from an adaptation of the market agents to the nuclear retirements is more complex and uncertain to predict. Some types of electricity market models (Sepulveda, 2016) can infer what type of generators and how many of them will replace the retired generators. As we can expect, the type of generators being build depends heavily on fuel prices (for dispatchable generators) and policy support (for renewables). For the purpose of brevity in this paper a simpler approach is employed. The wholesale market model is conserved while modifying the assumption on the installed capacity mix. In scenario 2 and 3, 20% of the nuclear capacity is replaced by new combined cycle plants and wind turbines respectively. The amount of capacity addition is inversely proportional to the capacity factor of the technology considered (0.87 for CCGT and 0.39 for Midwest wind for instance).

The effect on average wholesale electricity spot price is summarized in Table 6. As expected, in both cases the effect is much milder than the “short-term” effect where market agents do not have time to react. The price increase is about +$0.02/MWh in scenario 2 due to currently low gas prices (2015 gas prices are assumed: $3.2/ MMBtu average). In the Mid-Atlantic region, the effect would be negligible due to the fact that gas plants are infra-marginal and that coal plants still set the price of electricity (Figure 8). In scenario 3 where renewables replace nuclear, there is nearly zero price effect because wind replaces nuclear base-load generators. Wind and nuclear are always infra-marginal in the supply curve and never set the spot price of electricity.

4.4. Impact on Natural Gas Market and Fuel Security

The retirement of base-load nuclear increases the production of electricity from fossil fuel, and from natural gas in particular. This additional demand has a significant impact on the natural gas market. In scenario 1 (nuclear replaced by existing generators), the increase in natural gas burn is 570 Bcf/year, i.e. 2.1% of the total U.S. consumption[8]. In scenario 2 (nuclear replaced by modern CCGT), the increase is 1,020 Bcf/yr, 3.7% of the U.S. consumption. In scenario 3, there is no increase in gas consumption.

As seen previously in 3.1.4 and Figure 10, the replacement of nuclear plants by gas-fired plants would make electricity markets even more dependent on natural gas supply and therefore more sensitive to natural gas price variations. This high dependence could also jeopardize the security of electricity supply when natural gas is scarce (e.g. in case of polar vortex or pipeline failure).

4.5. Impact on the Cost of Generation

The average cost of generation of the nuclear capacity at risk is $36-37/ MWh over 2017-2019, which amounts to $5.8-6 B / yr for 20 GW of capacity. By comparison, the equivalent generation from new CCGT would come at a levelized cost of $25-38.5/ MWh[9] or $4.0-6.2 B / yr. The equivalent wind power generation would have a levelized cost of $34-47/MWh or $5.4-7.6 B / yr[10].

---

[8] The natural gas consumption in the U.S. in 2015 was 27,306 Bcf (EIA, 2016). The heat rate for existing natural gas power plant is assumed to be 7,476 Btu/kWh.

[9] Assumptions: 8% discount rate, CF= .4-.7, fuel price $2.4-5.2/MMBtu. Cost range based on Lazard, 2016.

[10] Assumptions: 8% discount rate, CF=.3-.55. Cost range based on Lazard, 2016.

4.6. Impact on the Cost of Subsidies

Preserving 20 GW of nuclear at risk would come at a cost of \$0.2 to 1.9 billion/ year, and \$1.9 to 12.0/ MWh[11]. This is well below the \$3.9 billion / yr cost of carbon damage – a price externality – caused by its retirement (\$41.8/MT CO_2 avoided according to the 2016 EPA cost of carbon damage and in scenario 2). Replacing nuclear by renewables would have a neutral impact on emissions, but doing so would be more costly than preserving the existing nuclear plants. As an illustration, the federal Production Tax Credit for wind power was \$23/MWh in 2016 (DOE). The most representative state subsidy, the Renewable Energy Certificates, traded at about \$13/MWh in 2015-2016 in PJM (more precisely, in PA/NJ/MA). Replacing 161 TWh/ yr of nuclear by wind electricity would therefore come at the "policy" cost of *at leas*t 161,000,000*36 = \$5.8 billion/ yr, which is several times greater than the estimated policy cost of preserving all the nuclear plants of the country.

Table 6 – Different scenarios can be inferred following the hypothetical retirement of 20 GW of U.S. nuclear capacity. The effects on emissions, wholesale electricity spot price, gas burn and costs are significant.

Scenario	**Reference**	**1**	**2**	**3**
Scenario description	**Nuclear fleet maintained**	**Retired nuclear replaced by existing sources**	**Retired nuclear replaced by modern CCGT**	**Retired nuclear replaced by renewables**
CO_2 emissions from power sect. and associated social cost	1,919 MM MT /yr	+5.8% +\$4.7 B damage/ yr	+3.2% +\$2.6 B damage/ yr	+ 0
Wholesale spot price of electricity	\$26.9/MWh (Midwest) \$31.8/MWh (Mid-Atl.)	+\$0.59/MWh (Midwest) +\$0.93/MWh (Mid-Atl.)	+\$0.02/MWh (Midwest) +\$0.00/MWh (Mid-Atl.)	+\$0.01/MWh (Midwest) +\$0.00/MWh (Mid-Atl.)
Gas burn	9,671 Bcf/yr (power sect.) 27,306 Bcf (U.S. total)	+570 Bcf/yr (+2.1% U.S. total)	+1,020 Bcf/yr (+3.7% U.S. total)	+0 Bcf/yr
Cost of generation	\$36-37/ MWh \$5.8-6.0 B/ yr	-	\$25-38.5/ MWh \$4.0-6.2 B/ yr	\$34-47/ MWh \$5.4-7.6 B/ yr
Cost of subsidies	\$1.9-12.0/ MWh \$0.2-1.9B/ year (revenue gap)	-	-	\$23 /MWh (federal PTC) ~ \$13/MWh (state REC) \$5.8 B/yr

[11] The width of the range corresponds to the profitability gaps of the plants we select for policy support. It is more expensive to support 20 GW of plants that are the very much "out-of-the-money" (\$12.0/ MWh) than 20 GW that are close to profitability (\$1.9/ MWh).

5. Regulatory Options for Maintaining the Nuclear Fleet

Previous results indicate that the irreversible retirement of nuclear capacity would have severe implications on energy and climate policy. On what basis should the regulator and policy-maker take action on the market?

In the absence of a price of carbon, zero-emission attributes are not valued by deregulated electricity markets. The cost of carbon emissions damage is a price externality. Deregulated markets favor the cheapest generation technologies, regardless of their carbon intensity. To compensate, subsidies have been set up to promote the installation of renewables in most countries (mostly wind and solar PV). These policy support mechanisms have taken multiple forms (Feed-in-Tariffs, Investment Tax Credit, etc.) but are similar in that they take place “out-of-the-market”. Some could argue that these “out-of-the-market” payments are a market fix but they are not equivalent to a carbon price: they are not given equally to all low-carbon technologies nor penalize carbon-intensive generators. In particular, nuclear and large-scale hydro do not benefit from these payments even though they are the largest contributors to carbon-free electricity in the United States. As a result, nuclear reactors have been competing directly with fossil-fuel technologies on one hand and subsidized renewables on the other hand (see figure below and prophetic article by Rothwell, 2000). A large share of the already-built, existing fleet is struggling financially, as discussed in section 2 and 3. It is needless to say that in these conditions capital investments in *new* nuclear are even less attractive, even for regulated utilities that enjoy lower discount rates[12]. Figure 14 exhibits the competitiveness gap for nuclear at the moment, on the basis of levelized cost of electricity (LCOE). LCOE has limitations – notably when it comes to compare the system cost of intermittent generators versus dispatchable generators – but it is a simple way to compare the competitiveness of technologies taken in isolation.

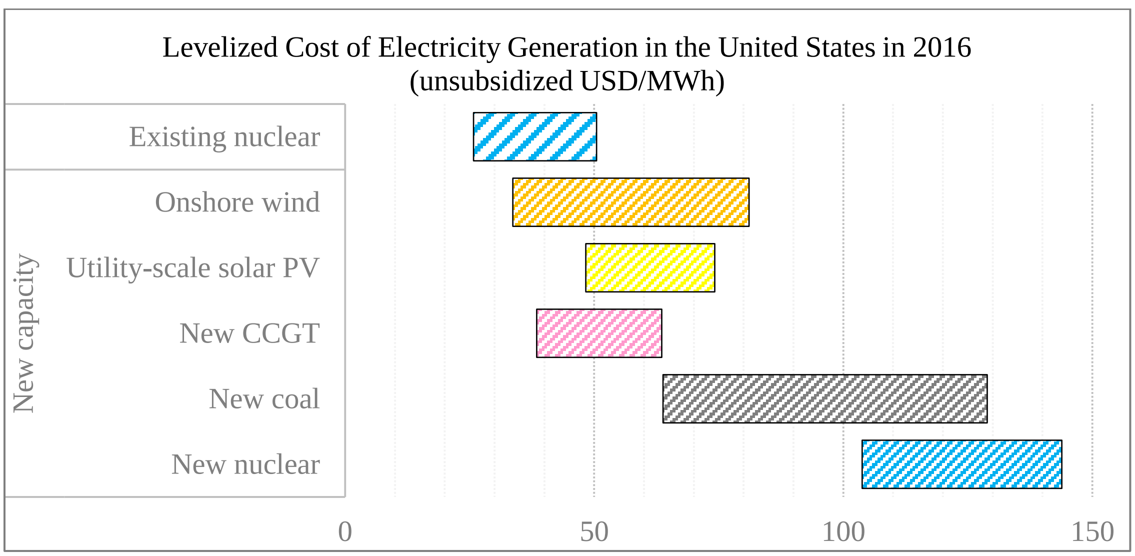


Figure 14. Under current costs, existing U.S. nuclear reactors are being replaced by CCGT units and subsidized renewables[13]. The capital cost assumptions are from Lazard (2016).

[12] The last decision to build new reactors, the four AP1000s in Vogtle and VC Summer, happened in 2007 in much more favorable economic conditions than today’s and with policy incentives from the federal government (Energy Policy Act of 2005).

[13] Assumptions: 8% discount rate, CF= .9 (nuclear), .3-.55 (wind), 0.23-0.32 (solar), 0.93 (coal), .4-.7 (CCGT), fuel price=$1.47/MMBtu (coal) and $2.4-5.2/MMBtu (NG), existing nuclear cost range based on 2016 estimates.

As seen in sections 2 and 3, the threat to nuclear capacity is immediate and invites to a rapid response, which could effectively, timely and decisively come from the policy-makers and regulators. This section discusses possible options that could relieve the financial pressure on nuclear. The discussion can also more broadly apply to any capital-intensive low-carbon energy resources.

5.1. Putting a Price on Carbon

Putting a price on carbon would capture the externality of environmental and societal damage caused by carbon emissions (I.J. Perez-Arriaga, 2013). Two systems are generally proposed for carbon price: a carbon tax or a cap & trade system. The carbon tax lets the regulator control the price level, with the risk of over- or under-shooting the emission targets. The cap & trade system relies on markets. The emission targets are set by the regulator who grants credits, which are then traded between generators. In the second system, the difficulty lies in the initial allocation of the credits.

Carbon pricing is a very efficient measure to achieve carbon emission reduction at a minimal cost. It is technology-neutral. It favors low-carbon generators at the expense of the carbon-intensive ones, such that the current “out-of-the-market” payments are no longer justified. It modifies the dispatch of the generators on the short-term and provides a long-term price signal that incentivizes innovative clean technologies to enter the market and displace the polluting and less efficient generators. However, putting a price of carbon is a challenge (E. Kee, 2016). One of the major obstacles is the increase in the energy price resulting from the addition of the cost of carbon, especially if it applies to all sectors of the economy including transportation. The price of goods would increase, which would hurt the economy in the short and medium term, even though the long-term damages are minimized on the long run. If carbon pricing is implemented unevenly on a given territory, the markets that adopt it face a competitive disadvantage with respect to the other markets because their products become pricier.

An intermediate approach was proposed by NEPOOL, an association of the market participants of ISO-NE (Exelon, 2016). It consists in adding the cost of carbon to the bids of the market participants, for calculation in the resource dispatch algorithm. Low carbon technologies like nuclear would benefit from a higher price of electricity, and low-carbon subsidies could be eliminated. An important element of the mechanism is the re-allocation of the carbon cost: carbon-emitting generators that are called and dispatched would compensate the ISO for their emissions. The proceedings would then be allocated to the load serving entities (i.e. the consumers) to lower their energy bill. This mechanism enables to partially alleviate the burden of carbon pricing to the consumer. This instrument could be created rapidly because the ISOs centrally control the dispatch algorithm.The carbon price could be small at the beginning and progressively increased. The out-of-the-market subsidies progressively reduced to ensure a smooth transition and give market agents time to adapt.

Table 7 illustrates the hypothetical outcome of a carbon price that would be applied to the Midwest and Mid-Atlantic regions. The simulations use the 2015 wholesale market model presented in section 3.1.1. A moderate carbon price as low as \$10 / MT CO_2 would provide extra revenues to the nuclear plants equal to \$7.2 and \$8.4/ MWh for the Midwest and Mid-Atlantic respectively. This would be enough to prevent most nuclear closures (according to Table 3). By allocating the cost of carbon to coal-, gas- and oil-fired generators, the price increase for the consumers would be limited to \$2.0 and \$4.6/ MWh respectively.

Table 7 – Putting a price on carbon lowers C02 emissions and increases the wholesale price of electricity, which would benefit nuclear plants. The price increase for consumers could be partly alleviated by charging the polluters for the cost of carbon damage (simulation results obtained with 2015 cost assumptions).

	Carbon price (\$/MT CO_2)	**0**	**10**	**20**	**30**	**41.2** **(EPA social cost of carbon)**
Midwest	Emissions (MM MT CO_2)	430.93	360.85	272.32	258.84	258.57

	Wholesale electricity price ($/MWh)	26.9	+7.2	+14.4	+23.1	+33.2
	Consumer price w/ rebate ($/MWh)	26.9	+2.0	+6.6	+12.0	+17.9
Mid-Atlantic	Emissions (MM MT CO_2)	271.90	263.15	263.00	262.99	262.99
	Wholesale electricity price ($/MWh)	31.8	+8.4	+16.9	+25.3	+34.8
	Consumer price w/ rebate ($/MWh)	31.8	+4.6	+9.2	+13.8	+18.9

5.2. Crediting Zero-Emission Attributes (direct subsidy)

Subsidies are the most direct way to value a specific attribute and maintain or expand a given generation resource. They are the most popular form of policy support, together with tac credits. Subsidies can take different name depending on the mechanism – Feed-in-Tariffs (FIT), Feed-in-Premiums (FIP), Contract-for-Differences (CfD), Zero-Emission Credits (ZEC), etc. – but in the end they result in an additional revenue for the targeted generator. They generally take the form of payment for the electricity supplied to the grid from a given technology or plant, and are expressed in $/MWh.

FITs have been a common method of policy support for wind and solar PV technologies at the beginning, but were later replaced in Europe by FIPs with competitive bidding. Premiums are a payment that is added to the wholesale electricity sale revenue rather than a substitutive fixed tariff. Note that subsidies through competitive bidding requires multiple independent agents to be effective. A CfD can be seen as a long-term power purchase agreement for the electricity generated from a particular source. The U.K. implemented a CfD program for new nuclear which led investors to the decision to build two large EPR reactors (E. Kee, 2015).

New York and Illinois States recently voted for another form of direct subsidy for nuclear, in the form of “Zero Emission Credits” (ZECs). Both New York and Illinois subsidies are based on the social cost of carbon, which is adjusted by an electricity price index (energy + capacity) in order to limit the cost to the consumers. The NY subsidy is revised every other year based on the EPA cost of carbon and a forward power market index. The formula is as follows:

$$ZEC(\$/MWh) = CarbonCost - RGGI - max(PriceIndex - 39{,}0)$$

with RGGI the Regional Greenhouse Gas Initiative payments ($10.4/short ton), and the carbon cost fixed at $42.9/short ton. The market price index is equal to the sum of the a) the day-ahead fixed price future and b) the capacity price, both averaged over two years in the zone (NY Public Service Commission, 2016). The initial ZEC calculation results in a subsidy of $17.5/MWh. If implemented, the subsidy will secure the continued operation of three nuclear plants (3.4 GW total capacity) in upstate New York for the next 14 years.

The Illinois program has a similar structure, with more provisions on the maximum payment that the plant owners can receive. Nuclear capacity is large in Illinois, and the regulator cannot afford to subsidize all of it. The subsidy is limited to 16% of electricity supplied to consumers, or 1.65% equivalent retail price increase on the bills of the consumers – whichever is larger[14]. The subsidy is updated every year based on market price indexes. The formula is the following:

$$ZEC(\$/MWh) = CarbonCost - max(PriceIndex - BaselinePrice, 0)$$

The carbon cost is originally taken at $16.5/ MWh and the baseline price at $31.4/MWh for the first calculation in

[14] These two are effectively equivalent to a maximum subsidy of about $206 million/year for Clinton and Quad Cities.

2017. The carbon cost is corrected for inflation in subsequent years. The price index is similar to the NY price index: it is a sum of a) the forward wholesale price at the Northern Illinois hub and b) the capacity price in Illinois, which is a 50/50 price blend of MISO zone 4 and PJM ComEd region (Illinois General Assembly, 2016). At current future prices, the subsidy amounts to ~\$14.7/MWh for the first year for Quad Cities and Clinton (2.9 GW total capacity).

From a design perspective, ZECs or other direct subsidies have the advantage of being closely controlled by the regulator or policy maker. The final dollar amount is set by the formulas above. Therefore, it can be tailored to the exact "competitiveness gap" that the technologies deserve and include provisions to prevent deviations. For instance the NY and Illinois subsidies target the specific plants at risk of shutdown and leave the profitable ones unsubsidized. To further guarantee the legitimacy of the subsidy, Illinois demands the plant owner to (privately) disclose its cost of generation.

History shows that in general it is difficult to determine the cost-effective level of direct subsidy that the generators deserve (Ito, 2015). Direct support programs have commonly been more costly than anticipated, and past experience shows that designers of FITs have often revised their tariff several times for the same country over a short period of time (for example in Spain). Frequent regulatory changes can send confusing signals to investors, whereas long-term vision and regulatory stability are essential for clean technologies to develop. To support large-scale investments in *new* nuclear, subsidies must be guaranteed for tens of years (35 years in the U.K.) and cannot be left at the mercy of changing political agendas.

Direct subsidies are effective but on the other hand they can have adverse effects. They distort the functioning of electricity markets, in particular the price signal for capacity entry and exit. They alter the "natural" generation mix and the bids of the generators, which are in some instance willing to bid negative prices to ensure their dispatch and receive policy payment. Negative prices have for instance appeared in several wholesale markets at times when energy demand is low and renewable generation large. The collapse of energy prices during some hours of the day negatively impacts the revenue of the technologies that do not benefit from the same treatment. The investment and retirement decision are modified because the price signal does not reflect the payments the market agents receive. Lastly, they create a source of uncertainty in competitive markets, since the legislator has the discretionary power to support a given set of resources with short notice. This phenomena can deter future investments because investors require long-term, transparent price signals to make decisions.

In some instances (such as the "Hughes vs. Talen Energy Marketing" case), the regulator (FERC in this case) rejected the instrument because it interfered too much with markets. When designing the mechanism for nuclear, it is therefore essential to stress the value of the zero-carbon attribute as well as avoiding the direct interference with day-ahead and real-time wholesale markets. The New York Clean Energy Standard was designed according to this principle.

In the case of early nuclear shutdown, the best merits of ZECs are their effectiveness, easiness and rapidity of implementation. If approved by the Federal Energy Regulatory Commission (FERC), the NY and Illinois subsidies will have taken less than a year to be designed, voted and implemented. More states could follow and adopt a similar ZEC to preserve their nuclear capacity.

5.3. Creating a Low-Carbon Capacity Mechanism

Capacity mechanisms are designed to ensure enough capacity is installed in the grid. They provide a substantial source of revenue to generators, especially those who run for a limited number of hours per year (the "peakers"). They solve the so-called "missing money" problem that occurs when energy prices are capped and they ensure the generators are properly remunerated for the reliability they offer (Joskow, 2006). Capacity mechanisms are therefore unnecessary when energy prices are not capped (such as in Texas, Australia). They are present in most deregulated markets of the United States (PJM, New England, New York, MISO, California) and in Europe. They enable the regulator to better control security of supply by running capacity auctions several years before delivery. Early auctions also lower the risk for investors because stakeholders know what capacity price and generation mix to expect before investing in new assets.

Capacity mechanisms can take several forms: capacity market, reliability options, or capacity payments. They are a relatively recent addition to energy markets; their design is still on-going and changes regularly. A recent change occurred in the PJM and New England capacity markets, following the 2014 polar vortex. The regulator now imposes heavy penalties the generators that clear the capacity market but are not available when needed (i.e. during scarcity periods). Bids and prices have consequently increased. The reform helps the most reliable generators such as nuclear and hydro be more profitable and competitive in the capacity market.

The advantage of capacity mechanisms is that they are already in place in many regions. They are a market-based approach to value reliability: the capacity needed is forecasted by the regulator and the price is given by market. It also means that the capacity price may be zero if there is over-capacity in the grid. From a design perspective, the rules of the capacity auction (time-to-delivery) are crucial for determining which new technologies can bid. If the costs of new generation change, the technology being built may be different than the one the policy-maker expected in the first place.

A more oriented and innovative approach to value reliable, low-carbon generation capacity could be to add an environmental dimension to capacity mechanisms. It would give an instrument for policy makers to ensure that a “cleaner” capacity and energy mix is achieved. The concept would be to give a premium to zero-carbon technologies and/or a penalty to carbon-emissive technologies. The environmental dimension could be directly included in the market clearing algorithm (case of a penalty), or occur after market clearing (case of a premium/ credit). The capacity auction could alternatively be set in a separate capacity market dedicated to low-carbon resource. The tender for low-carbon capacity would be run 5 to 10 years before the date of capacity delivery, such as large infrastructure projects such as nuclear and hydro –with or without new transmission lines– could compete. The demand-side of the capacity market would be composed of aggregators, large consumers and retailers. The auction would be run by the regulator or grid operator. The “clean” capacity mechanism would allow the regulator to better control the capacity mix. As a downside, load-follow and peak generators (coal, gas-fired and oil-fired) could accelerate their retirement if their capacity payments drop too quickly. It may have detrimental consequences on grid reliability and the cost of energy (currently, there is no cheap zero-emission substitute to “dirty generators” for peak generation). Therefore, the transition from classical to clean capacity mechanism should be progressive to prevent the disruption of peak power supply.

5.4. Expanding Low-Carbon Portfolio Standards

A portfolio standard is a system where electricity providers are mandated to buy a certain target of “clean” electricity, i.e. generated from clean energy sources. Certificates are granted to clean energy generators for the electricity they produce. They are then traded on an exchange platform, which provides extra revenue to the clean generators. In the U.S., portfolio standards usually comprise renewables but not nuclear nor large hydro. A more consistent approach would be to include *all* low-carbon generators in these portfolios. The nuclear fleet, with its large electricity output, would benefit considerably from this measure.

The advantage of a portfolio standard as opposed to a direct subsidy (FIT, ZEC, CfD, etc.) is that the price is set by the market instead of being dictated by the regulator of policy maker. Only the target will need to be decided in advance. Renewable portfolio standards already exist in many states of the U.S., and adding other technologies would be a minimal modification to the rules – albeit it would change the price equilibrium of the certificates. The regulator would have to adjust the mandates to prevent too much disruption.

As a disadvantage, the regulator does not directly control the level of investment in clean technologies. The price is given by the market and can be too low if excess clean generation is present. If certificates are inexpensive, new investment in low-carbon technologies will stall.

If there is a single portfolio standard, all clean generation technologies are remunerated at the same price ($/MWh). Renewables would compete with nuclear on an equal field. Alternatively, the regulator can create several portfolio standards to differentiate different technologies. For instance in Massachusetts, solar PV has its own standard and does not directly compete with wind. The certificates from solar PV do not trade at the same price as the certificates from wind.

5.5. Cost-Effective Mothballing of Nuclear Assets

As seen previously, current market conditions displace nuclear power plants in the United States. They retire and enter the decommissioning process a few months later, preventing their restart forever (DOE/INL, 2016). What if we could restart them at a minimal cost when the market conditions improve? This is the mothballing option. The idea of mothballing a non-profitable nuclear asset is not new. It was for instance proposed in the 1970's for the Zion plant, or more recently by E. Kee (2015, 2016 and NECG, 2015). It consists of temporarily stopping the generation of electricity for a few years in the hope that the market conditions will get better.

For the mothballing option to be applied, it is necessary for the cost of mothballing to be lower than the expected loss of continued operation. The expected losses in operation ranged in 2016 from $0 to 32/MWh throughout the fleet, with an average at $7.5/MWh. Can the cost of mothballing be lower than this?

Unlike fossil-fuel generators, the cost of nuclear generation has a very large fixed component due to security and operation personnel (labour), routine inspection and maintenance. These fixed cost average to $18-19/MWh. Variable costs (fuel and variable O&M) represent the rest: 40 to 60% of the annual cost of generation. We see immediately that stopping the plant and saving the variable cost is not sufficient for preventing plants to lose money. This is why premature retirements have so far been the only option for uneconomic plants to stop losing money. The temporary shutdown of a plant for several years has not been considered due to high fixed cost required for security, safety and equipment care.

The mothballing option would become interesting for nuclear operators only if the fixed cost requirements were lowered. After all, once the reactor has been shut-down and the core has cooled down, the risk of an accident or malevolent act is considerably reduced. This would justify to lower the safety and security requirements, two major cost items[15]. Unfortunately, there is no special regulatory status for a mothballed plant in the United States currently. The Nuclear Regulatory Commission (NRC) recognizes only two types of regulatory status: a nuclear plant is either under an operation license or under a decommissioning license. It would be desirable to create a mothballing license for uneconomic plants. This new licensing status would define a set of reduced requirements to lower the cost of mothballing down to 7.5*8760*0.92 = ~$60 million / GW-yr. Society would then preserve the option to restart these zero-emission generation assets in the future when appropriate. Note that the mothballing option would also preserve the option to extend the lifetime of the plants. Mothballing should be a preferable alternative to irreversible retirement.

There is indeed a fundamental policy issue beyond the near-term decisions. The historical energy record has been one of major surprises—from the oil embargo of the 1970s to natural gas fracking. Once we shut down and decommissions major facilities, there is a large cost in dollars and time to rebuild if conditions change. The future is uncertain and that uncertainty should be an essential consideration of any public policy. Two examples going forward urge caution on irrevocable decisions. If a major event occurred, similar to the oil shock of the 1970s, energy policies could change overnight with the demand for rapid reductions in greenhouse gas emissions with every technology available. If a major weather event occurs, the limits of other low-carbon options such as renewables would require rethinking. The January 2017 weather in Germany (low solar and low wind) that dramatically reduced renewables output resulted in every fossil plant in Europe powering up—an unexpected weather event..

6. Conclusion and Policy Implications

The drops in wholesale electricity prices over the past few years have exerted significant pressure on nuclear power capacity in the United States. These low prices, mostly caused by negative demand growth and cheap

[15] Recent progress in dry cask fuel storage technology could accelerate fuel unloading and reduce the safety requirements after shutdown faster than in the past (Holtec, 2017). Fuel could go to dry cask storage as early as 2.5 years after cooldown rather than 5 or more years currently.

natural gas, are expected to persist. About 58 GW of nuclear capacity are unprofitable over the next few years, with a profitability gap of $5.5-7 / MWh on average. 12 GW of merchant plants are unprofitable with an average revenue shortfall of $3.5-5.5 / MWh. They are at risk of premature retirement and may add to the 6.5 GW of already-announced retirements

The potential consequences of a massive capacity withdrawal depend on the future energy mix. If 20 GW were replaced by modern gas-fired combined cycle plants, U.S. gas burn and carbon emissions from the power sector would increase by 3.7% and 2.6% respectively in estimates. Electricity markets would rely even more heavily on natural gas. If replaced by renewables (wind), the withdrawal would be carbon-neutral, but the policy cost would be severe. The federal tax credit and Renewable Portfolio Standards (RPS) program alone would cost more than $5 billion/ year in subsidies. In comparison, saving 20 GW of unprofitable nuclear plants could come at a cost of only $0.2-1.9 billion/ year for the consumers.

In a context of uncertainty about future fuel prices, technological progress, and climate policy, the irreversible closure of nuclear assets should be delayed. Maintaining the U.S. nuclear capacity via a policy support mechanism in the short term is an affordable measure that preserves optionality. Today, it is at least two to four times more cost-effective to subsidize existing reactors than it is to subsidize renewables on a $/MWh basis.

The New York and Illinois “zero-emission credits” are an effective way to rapidly save nuclear plants at risk. But, similarly to renewables feed-in-tariffs, these payments take place out-of-the-market. Carbon pricing is an alternative policy option that would preserve the market price signal and benefit nuclear plants first. Its wide implementation is a long process, but it could be tested at the State or ISO level before broader application. A carbon price as low as $10 / MT CO_2 would be sufficient to maintain most U.S. nuclear capacity.

Alternative regulatory options we discussed are the expansion of the RPS to include nuclear, the transition to “cleaner” capacity mechanism, and the creation of a mothballing status for unprofitable nuclear reactors.

In parallel with policy actions, the nuclear industry should continue its efforts to lower costs and adapts its technology. Automation, simplified Small Modular Reactors (Locatelli, 2014), offshore reactors (Haratyk, 2014), and nuclear energy storage technologies (Forsberg, 2016) are promising advances that could help nuclear be part of future low-carbon, deregulated electricity markets.

Acknowledgements

I would like to warmly thank my thesis advisors, Professors R. K. Lester, C. W. Forsberg and J. E. Parsons, for their help and advice in reviewing this paper. R.K. Lester and J.E. Parsons are MIT CEEPR faculty affiliates. We are also very grateful to the U.S. Department of Energy for supporting this research and for the cooperation of the Ministry of Economy, Trade and Industry (METI) of Japan.

References

American Nuclear Society (ANS) Special Committee on Nuclear in the States, 2016. “Nuclear in the States Toolkit – Policy options for states considering the role of nuclear power in their energy mix”, 2016

L. Davis and C. Hausman, 2016. “Market Impacts of a Nuclear Plant Closure”, American Economic Journal: Applied Economics, Vol.2, No. 2, pp. 92-122, 2016.

U.S. Department of Energy (DOE) / Idaho National Laboratory (INL), 2016. “Economic and Market Challenges Facing the U.S. Nuclear Commercial Fleet”, INL/EXT-16-39951, 2016.

J. M. Deutch, C.W. Forsberg, A.C. Kadak, M.S. Kazimi, E.J. Moniz. and J.E. Parsons, 2009. “Update of the MIT 2003 Future of Nuclear Power, an Interdisciplinary MIT Study”, Massachusetts Institute of Technology Energy Initiative report, 2009.

Energy Information Administration (EIA), 2016. Electricity Data Browser: http://www.eia.gov/electricity/data.cfm.

Energy Information Administration (EIA), 2016. “Form EIA-923 detailed data”. https://www.eia.gov/electricity/data/eia923/

Energy Information Administration (EIA), 2009. “Short-Term Energy Outlook Supplement: Energy Price Volatility and Forecast Uncertainty”.
Exelon, 2016. “Using Carbon Pricing in Dispatch to Meet the IMAPP Process Goal”, Presentation at NE Pool meeting, August 2016.
C. Forsberg and P. Peterson, 2016. “Basis for Fluoride Salt–Cooled High-Temperature Reactors with Nuclear Air-Brayton Combined Cycles and Firebrick Resistance-Heated Energy Storage”, Nuclear Technology, Vol. 196, Pp. 13–33, October 2016.
G. Haratyk, F.X. Briffod and C. Lecomte., 2014. “Flexblue®: a subsea and transportable small modular power plant”, Proc. of ICAPP, Charlotte, USA, 2014.
G. Harris, P. Heptonstall, R. Gross and D. Handley , 2013. “Cost estimates for nuclear power in the UK”, Energy Policy, Volume 62, November 2013, Pages 431-442, 2013.
Holtec International, 2017. “Bolstering Public Health and Safety by Proto-Prompt Decommissioning of Closing Nuclear Plants”, Press Release HH 32.02, Jan 2017. https://holtec.files.wordpress.com/2017/01/hh-32_02.pdf
Illinois General Assembly, Bill 2814, 2016. http://www.ilga.gov/legislation/fulltext.asp?DocName=09900SB2814&GA=99&SessionId=88&DocTypeId=SB&LegID=96125&DocNum=2814&GAID=13&Session=
IEA, 2016. “Re-powering Markets: Market Design and Regulation during the Transition to Lowe-Carbon Power Systems”, IEA Electricity Market Series, 2016.
Y. Ito, 2015. “A Brief History of Measures to Support Renewable Energy: Implications for Japan’s FIT Review obtained from Domestic and Foreign Cases of Support Measures”, Institute for Energy Economics of Japan (IEEJ) report, https://eneken.ieej.or.jp/data/6330.pdf, 2015.
P. Joskow, 2006. “Competitive Electricity Markets and Investment in New Generating Capacity”, AEI-Brookings Joint Center Working Paper No. 06-14, May 2006.
P. Joskow and J. Parsons, 2009. “The Economic Future of Nuclear Power”, Daedalus, Vol.138, No. 4, 2009.
P. Joskow and J. Parsons, 2012. “The Future of Nuclear Power after Fukushima”, Economics of Energy & Environmental Policy, Vol. 1, No. 2, 2012.
E. Kee, 2015. “Can nuclear succeed in liberalized power markets? ”, World Nuclear News article, http://www.world-nuclear-news.org/V-Can-nuclear-succeed-in-liberalized-power-markets-0420152.html , 2015.
E. Kee and E. Zoli, 2014. “Rescuing U.S. Merchant Nuclear Power: Advancing National Security, Economic, Energy and Environmental Imperatives”, The Electricity Journal, Vol. 27, Issue 3, pp. 8-17, 2014.
E. Kee, 2016. “Carbon pricing not enough to help nuclear power”, World Nuclear News article, http://www.world-nuclear-news.org/V-Carbon-pricing-not-enough-to-help-nuclear-power-10061601.html , 2016.
E. Kee, 2016. “’Market failure’ and nuclear power”, Bulletin of the Atomic Scientists, http://thebulletin.org/%E2%80%9Cmarket-failure%E2%80%9D-and-nuclear-power9703 , 2016
E. Kee and E. Zoli, 2014. “Rescuing U.S. Merchant Nuclear Power: Advancing National Security, Economic, Energy and Environmental Imperatives”, The Electricity Journal, Vol. 27, Issue 3, pp. 8-17, 2014.
J. Koomey and N. Hultman, 2007. “A Reactor-Level Analysis of Busbar Costs for US Nuclear Plants, 1970-2005”, Energy Policy, Vol 35, pp. 5630-5642, 2007.
Lazard, 2016. “Lazard’s Levelized Cost of Energy Analysis – Version 10.0”, Dec 2016.
P. Linares and A. Conchado, 2013. “The Economics of New Nuclear Power Plants in Liberalized Electricity Markets”, Energy Economics, Vol. 40, pp.S119-S125, 2013.
G. Locatelli, C. Bingham and M. Mancini, 2014. “Small Modular Reactors: A Comprehensive Overview of their Economics and Strategic Aspects”, Progress in Nuclear Energy, Volume 73, May 2014, Pages 75-85, May 2014.
K. Maize, 2016. “Entergy Sheds Uneconomic Merchant Nuclear Plants to Focus on Regulated Business”, Power magazine article, April 1st, 2016, http://www.powermag.com/entergy-sheds-uneconomic-merchant-nuclear-plants-focus-regulated-business/?pagenum=1
North American Electric Reliability Council (NERC), 2016. Generating Availability Data System, http://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx. , 2016.

Nuclear Economics Consulting Group (NECG), 2014. “Nuclear Power & Short-Run Marginal Cost”, Commentary #2, http://nuclear-economics.com/nuclear-power-short-run-marginal-cost/, 2014

Nuclear Economics Consulting Group (NECG), 2014. “Nuclear Base Load”, Commentary #3, http://nuclear-economics.com/nuclear-base-load/, 2014

Nuclear Economics Consulting Group (NECG), 2015. “Flexible Nuclear Power”, Commentary #12, http://nuclear-economics.com/12-nuclear-flexibility/ , 2015.

OECD-NEA, 2011. “Carbon Pricing, Power Markets and the Competitiveness of Nuclear Power”, NEA report No. 6982, 2011.

OECD-NEA, 2015, “Nuclear New Build: Insights into Financing and Project Management”, NEA Report No. 7195, 2015.

A. Okagawa, 2012. “Assessment of GHG emission reduction pathways in a society without carbon capture and nuclear technologies”, Energy Economics, Volume 34, Supplement 3, December 2012.

I.J. Perez-Arriaga and C. Meseguer, 1997. “Wholesale Marginal Price in Competitive Generation Markets”, IEEE Transactions on Power Systems, Vol. 12, No. 2, May 1997.

I.J. Perez-Arriaga, 2013. Regulation of the Power Sector, Springer Verlag, London, 2013.

NY Public Service Commission, 2016. “Staff's Responsive Proposal For Preserving Zero-Emissions Attributes”. July 2016.

Nuclear Energy Institute (NEI), 2016. US Nuclear Generating Statistics: http://www.nei.org/Knowledge-Center/Nuclear-Statistics/US-Nuclear-Power-Plants/US-Nuclear-Generating-Statistics.

Nuclear Energy Institute (NEI), 2016. Nuclear Costs in Context. NEI White Paper.

Nuclear Regulatory Commission (NRC), 2016. Status of License Renewal Applications and Industry Activities: http://www.nrc.gov/reactors/operating/licensing/renewal/applications.html

F. Roques, W. Nuttal, D. Newbery, R. de Neufville and S. Connors, 2006. “Nuclear Power: A Hedge against Uncertain Gas and Carbon Prices?”, The Energy Journal, Vol.27, No.4, 2006.

C. Rorke, 2016. Where Have All the Nuclear Plants Gone? R Street Policy Study No. 70, 2016.

G. Rothwell, 2000. “The Risk of Early Retirement of U.S. Nuclear Power Plants under Electricity Deregulation and CO_2 Emission Reductions.” The Energy Journal, vol. 21, no. 3, pp. 61–87, 2000.

N. Sepulveda, 2016. “Decarbonization of Power Systems: Analyzing Different Technological Pathways”, Master’s Thesis, MIT, 2016.

R. Sims, H.H. Rogner and K. Gregory, 2003. “Carbon Emission and Mitigation Cost Comparisons between Fossil Fuel, Nuclear and Renewable Energy Resources for electricity Generation”, Energy Policy, Vol. 31, pp. 1315-1326, 2003.

SNL Financial, 2016. SNL Modeled Production Costs. www.snl.com.

SNL Financial, 2016. Generation Supply Curve Assumption and Methodology. https://www.snl.com/help/Generation_Supply_Curve.htm?rhtocid=3.10.0_1#

N. Steckler, 2016. Reactors in the Red: Financial Health of the US Nuclear Fleet. Bloomberg New Energy Finance research note.

US Government Interagency Working Group on Social Cost of Greenhouse Gases, 2016. “Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866”, August 2016.

F. Zhang, 2007. “Does Electricity Restructuring Work? Evidence from the U.S. Nuclear Energy Industry”, The Journal of Industrial Economics, Vol. LV, No. 3, September 2007

Appendix A. Wholesale electricity market model and assumptions

The formulation of the economic dispatch problem is as follows:

Find:

$$\min_{\substack{q_{i,n},\\ q_{VOLL,n}}} \left(\sum_{\substack{generator\ i\\ hour\ n}} (\mathrm{c}_i + cc_i) q_{i,n} + \mathrm{c}_{VOLL} q_{VOLL,n} \right)$$

With

c_i variable cost of generation for generator i
cc_i cost of CO_2 emissions for generator i
$q_{i,n}$ power output of generator i during hour n
c_{VOLL} value of lost load
$q_{VOLL,n}$ lost load during hour n

Subject to :

- Power demand constraint

$$\sum_{generator\ i} q_{i,n} + q_{VOLL,n} = d_n\ ,\ \ \forall n$$

with d_n the total electricity demand during hour n

- Minimum and maximum power constraint for each generator (except solar PV)

$$q_{i,min} < q_{i,n} < q_{i,max}\ \ ,\ \ \forall i, n$$

- Minimum and maximum power from wind power generators during each hour of the year (curtailment is allowed)

$$0 < q_{wind,n} < q_{windMax,n}\ \ ,\ \ \forall n$$

- Minimum and maximum ramping rate (change in power output of the generator between two consecutive hours)

$$q_{i,n} + \underline{q_i} < q_{i,n+1} < q_{i,n} + \overline{q_i}\ \ ,\ \ \forall i, n$$

with $\underline{q_i}$ and $\overline{q_i}$ the maximum change in output down and up (MW/hour) respectively for generator i

The generators parameters for each year and region are listed in Table 8, Table 9, Table 10 and Table 11. We assume that the generators bid at their short-run marginal cost of production, which is in general true for all generators in a perfect competition environment. The case of nuclear is different because there are no cost savings associated with variable output. A nuclear plant incurs the cost of fuel and O&M whatever the power history is. This is why the short-term marginal cost of production from nuclear – and therefore its supply bid –

is zero (NECG, 2014).

Table 8 – Cost and technical assumptions for generators in the Midwest region in 2015

Generator name	Nameplate capacity (MW)	Availability (%)	Fuel price ($/MMBtu)	Heat rate (MMBtu/ MWh)	Fuel cost ($/ MWh)	Variable O&M cost ($/MWh)	Supply bid = marginal production cost ($/MWh)	Ramp up (%/hr)	Ramp down (%/hr)
Nuclear	20,200.5	0.92	0.72	10458	7.5	0.63	0	0%	0%
coal_IA	5,638.1	0.83	1.47	10495	11.3	5.50	16.8	31%	58%
coal_IL	14,658	0.83	1.75	10495	15.4	4.27	19.7	31%	58%
coal_IN	16,611.5	0.83	2.65	10495	18.2	5.36	23.5	31%	58%
coal_MI	10,743.7	0.83	2.33	10495	18.4	5.62	24.0	31%	58%
coal_MN	4,169.9	0.83	1.74	10495	18.3	7.31	25.6	31%	58%
coal_MO	12,101	0.83	1.73	10495	21.9	4.43	26.3	31%	58%
coal_ND	4,195.1	0.83	1.07	10495	24.5	4.78	29.3	31%	58%
coal_WI	7,220.1	0.83	2.09	10495	27.9	8.94	36.8	31%	58%
CCGT_IA	2,630.5	0.85	3.23	7878	25.4	6.07	31.5	82%	75%
CCGT_IL	13,507.7	0.85	3.23	7878	25.4	5.08	30.5	82%	75%
CCGT_IN	5,069.9	0.85	3.23	7878	25.4	2.15	27.6	82%	75%
CCGT_MI	7,492.9	0.85	3.21	7878	25.3	2.84	28.1	82%	75%
CCGT_MN	4,776.9	0.85	3.23	7878	25.4	4.91	30.4	82%	75%
CCGT_MO	5,499.7	0.85	3.23	7878	25.4	8.01	33.5	82%	75%
CCGT_ND	328	0.85	2.89	7878	22.8	2.01	24.8	82%	75%
CCGT_WI	5,945	0.85	3.23	7878	25.4	4.19	29.6	82%	75%
CCGT_new	0	0.87	3.23	6600	21.3	2.75	24.1	82%	75%
GT	9,120.1	1.00	6.74	10987	74.1	15	89.1	82%	75%
Hydro	2,144	0.51	0	0	0.0	0	0.0	5%	5%
Wind	19,271.1	CF=0.39	0	0	0.0	0	0.0	0%	0%
Total	**171,323.7**								

Table 9 – Cost and technical assumptions for generators in the Midwest region in 2008

Generator name	Nameplate capacity (MW)	Availability (%)	Fuel price ($/MMBtu)	Heat rate (MMBtu/ MWh)	Fuel cost ($/ MWh)	Variable O&M cost ($/MWh)	Supply bid = marginal production cost ($/MWh)	Ramp up (%/hr)	Ramp down (%/hr)
Nuclear	20,368	0.91	0.51	10452	5.29	0.56	0	0%	0%
coal_IA	6,528	0.84	1.01	10378	10.53	5.62	16.14	31%	58%
coal_IL	15,117	0.84	1.40	10378	14.50	3.53	18.03	31%	58%
coal_IN	18,916	0.84	2.03	10378	21.10	4.35	25.45	31%	58%
coal_MI	11,597	0.84	1.92	10378	19.90	4.43	24.33	31%	58%
coal_MN	5,077	0.84	1.48	10378	15.40	6.28	21.68	31%	58%
coal_MO	11,146	0.84	1.33	10378	13.79	4.28	18.07	31%	58%
coal_ND	4,098	0.84	0.72	10378	7.50	4.07	11.57	31%	58%
coal_WI	7,316	0.84	1.74	10378	18.04	5.19	23.23	31%	58%
CCGT_IA	2,395	0.88	9.02	8305	74.91	4.17	79.08	82%	75%
CCGT_IL	13,462	0.88	10.10	8305	83.88	13.42	97.30	82%	75%
CCGT_IN	5,360	0.88	9.61	8305	79.81	6.04	85.85	82%	75%
CCGT_MI	8,430	0.88	8.75	8305	72.67	9.27	81.93	82%	75%
CCGT_MN	4,226	0.88	9.23	8305	76.66	5.02	81.68	82%	75%

CCGT_MO	5,550	0.88	9.02	8305	74.91	5.11	80.02	82%	75%
CCGT_ND	10	0.88	9.02	8305	74.91	3.89	78.81	82%	75%
CCGT_WI	6,165	0.88	9.24	8305	76.74	7.03	83.77	82%	75%
CCGT_new	0	0.87	3.23	6600	21.3	2.75	24.1	82%	75%
GT	9,557	1.00	10.87	11015	119.73	19.39	139.12	82%	75%
Hydro	2,136	0.43	0	0	0	0	0	5%	5%
Wind	6,482		0	0	0	0	0		
Total	163,936								

Table 10 – Cost and technical assumptions for generators in the Mid-Atlantic region in 2015

Generator name	**Nameplate capacity (MW)**	**Availability (%)**	**Fuel price ($/MMBtu)**	**Heat rate (MMBtu/ MWh)**	**Fuel cost ($/ MWh)**	**Variable O&M cost ($/MWh)**	**Supply bid = marginal production cost ($/MWh)**	**Ramp up (%/hr)**	**Ramp down (%/hr)**
nuclear	21,236.7	0.92	0.72	10458	7.48	0.63	0	0%	0%
coal_DE	410	0.83	4.29	10495	45.05	8.99	54.05	31%	58%
coal_KY	13,436.7	0.83	2.54	10495	26.64	3.74	30.39	31%	58%
coal_MD	4,472	0.83	3.74	10495	39.28	6.49	45.77	31%	58%
coal_NJ	782	0.83	5.10	10495	53.49	6.70	60.19	31%	58%
coal_OH	15,231.5	0.83	2.77	10495	29.10	5.70	34.80	31%	58%
coal_PA	12,989	0.83	2.63	10495	27.59	4.33	31.93	31%	58%
coal_VA	4,028.8	0.83	3.52	10495	36.92	8.25	45.17	31%	58%
coal_WV	12,908	0.83	2.92	10495	30.67	3.01	33.68	31%	58%
CCGT_DE	2,465	0.85	3.23	7878	25.45	1.77	27.22	82%	75%
CCGT_KY	5,616.9	0.85	3.23	7878	25.45	1.19	26.63	82%	75%
CCGT_MD	2,900	0.85	4.06	7878	31.98	1.87	33.86	82%	75%
CCGT_NJ	10,758.1	0.85	2.96	7878	23.32	4.05	27.37	82%	75%
CCGT_OH	9,512.5	0.85	2.42	7878	19.06	2.73	21.80	82%	75%
CCGT_PA	11,516	0.85	2.52	7878	19.85	2.17	22.02	82%	75%
CCGT_VA	9,452.9	0.85	3.55	7878	27.97	1.67	29.64	82%	75%
CCGT_WV	1,071.3	0.85	3.23	7878	25.45	4.19	29.64	82%	75%
CCGT_new	0	0.87	3.23	6600	21.3	2.75	24.1	82%	87%
GT	14,000.8	1.00	6.74	10987	74.05	15	89.05	82%	75%
hydro	3,502.1	0.33	0	0	0.00	0	0	82%	75%
wind	2,527		0	0	0.00	0	0	5%	5%
Total	158,817.30								

Table 11 – Cost and technical assumptions for generators in the Mid-Atlantic region in 2008

Generator name	**Nameplate capacity (MW)**	**Availability (%)**	**Fuel price ($/MMBtu)**	**Heat rate (MMBtu/ MWh)**	**Fuel cost ($/ MWh)**	**Variable O&M cost ($/MWh)**	**Supply bid = marginal production cost ($/MWh)**	**Ramp up (%/hr)**	**Ramp down (%/hr)**
nuclear	20,708	0.91	0.51	10452	5.29	0.56	0	0%	0%
coal_DE	780	0.84	4.46	10378	46.31	3.96	50.28	31%	58%
coal_KY	14,302	0.84	2.48	10378	25.74	2.95	28.70	31%	58%
coal_MD	4,704	0.84	4.63	10378	48.08	3.66	51.74	31%	58%
coal_NJ	1,573	0.84	4.04	10378	41.96	4.59	46.56	31%	58%

coal_OH	21,742	0.84	2.36	10378	24.49	4.92	29.41	31%	58%
coal_PA	17,561	0.84	2.33	10378	24.22	3.55	27.77	31%	58%
coal_VA	5,069	0.84	3.41	10378	35.41	6.41	41.82	31%	58%
coal_WV	14,486	0.84	2.64	10378	27.38	2.75	30.13	31%	58%
CCGT_DE	1,313	0.88	9.02	8305	74.91	3.31	78.22	82%	75%
CCGT_KY	4,615	0.88	9.02	8305	74.91	3.19	78.10	82%	75%
CCGT_MD	1,728	0.88	11.16	8305	92.68	2.05	94.73	82%	75%
CCGT_NJ	8,033	0.88	10.78	8305	89.53	4.44	93.96	82%	75%
CCGT_OH	8,169	0.88	10.79	8305	89.61	2.16	91.77	82%	75%
CCGT_PA	8,270	0.88	10.46	8305	86.87	2.23	89.11	82%	75%
CCGT_VA	6,982	0.88	10.87	8305	90.28	2.76	93.04	82%	75%
CCGT_WV	1,042	0.88	10.08	8305	83.71	7.03	90.74	82%	75%
CCGT_new	0	0.87	3.23	6600	21.3	2.75	24.1	82%	87%
GT	19,378	1.00	10.87	11015	119.73	19.39	139.12	82%	75%
hydro	3,107	0.31	0	0	0	0	0	82%	75%
wind	706		0	0	0	0		5%	5%
Total	164,268								

The solving of the cost minimization procedure yields the hourly dispatch of the generator as well as the average marginal cost of meeting electricity demand (dual variable of the demand constraint), which is equal to the wholesale electricity spot price.

For validation purposes, we plotted the simulated mix and average spot prices which we compared to their actual, historical values. The mix is in reasonable agreement, except for the Mid-Atlantic region in 2015. This is due to the close marginal cost from CCGT and from coal. The two technologies are very close in the merit order of the supply stack. It would require a more a more granular modelling of the CCGT and coal units in the region to reproduce the actual mix. However this is not needed to reproduce the actual price of electricity, which is simulated accurately. Another simulation discrepancy is the price in Midwest region in 2008. The average spot price is very sensitive to the coal power plant heat rate and availability assumptions, which we may have overestimated. The numbers we use for heat rate and availability come respectively from SNL (2016) and NERC (2016).

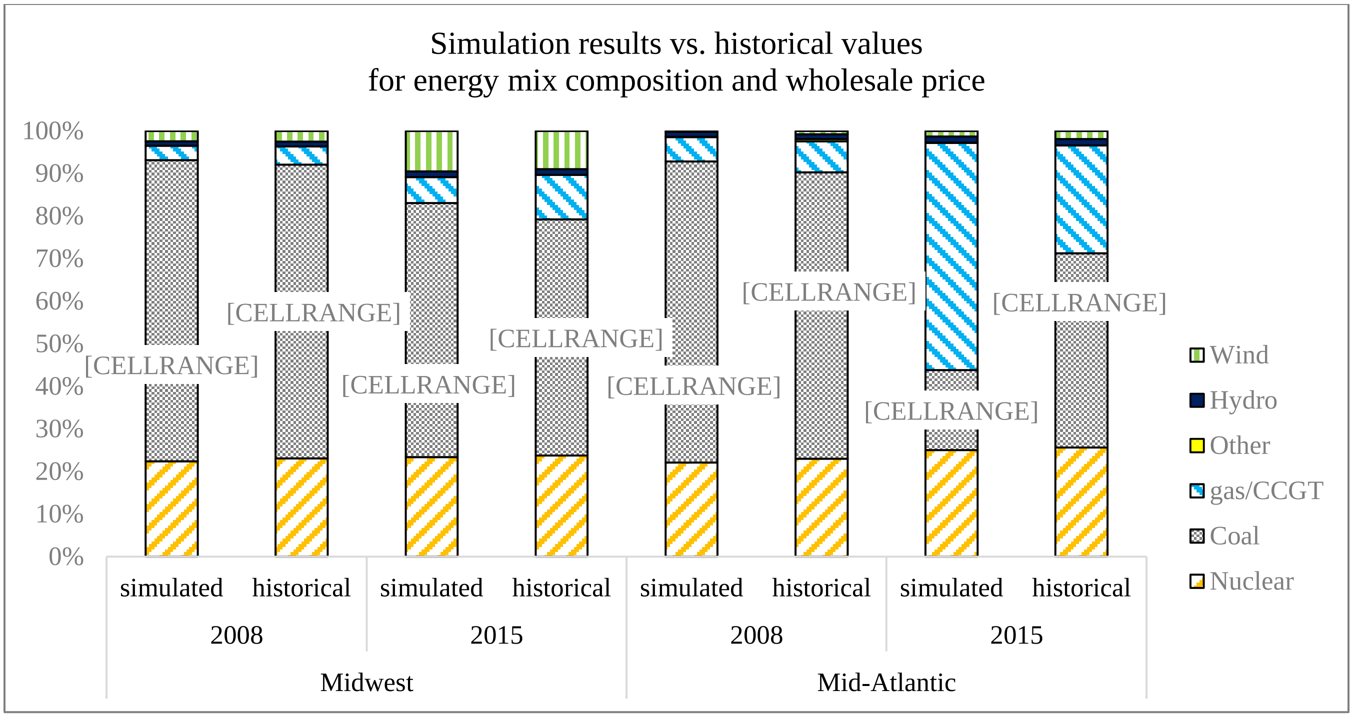


Figure 15. The simulations are in reasonable agreement with the historical spot prices and energy mix despite the simplicity of the model.